Code Review Programme 2016

Consultation paper

Submissions close: 5pm 29 November

18 October 2016
Contents

1  What this consultation paper is about 3
2  Code Review Programme 2016 5
3  Regulatory Statements for the proposed amendments 7

Appendix A  Format for submissions 8
Appendix B  Proposed Amendments 10
Appendix C  Drafting schedules 84
CRP 2016-07  Removing market administrator functions 85
CRP 2016-08  Transitional Provisions 102
CRP 2016-09  Changing the way Transpower makes grid information available 109
CRP 2016-10  Simplifying Code terms about time 117
CRP 2016-11  Rationalising references to registry and registry manager 132
CRP 2016-12  Simplifying Code terms about supply of electricity 149
CRP 2016-13 and CRP 2016-14:  Simplifying how information is published, and how the information system is defined. 232
CRP 2016-15  Simplifying Code terms about ‘notifying’ information 297
1 What this consultation paper is about

The Authority is proposing a range of small Code changes

1.1 The purpose of this paper is to consult with interested parties on the Authority’s proposal to make a range of small changes to the Code. The Authority believes the proposed changes will clarify and simplify language and processes, and make it easier for participants to understand their Code obligations.

1.2 Section 39(1) of the Electricity Industry Act 2010 requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. 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.

1.3 If the Authority is satisfied that an amendment is technical and non-controversial, it need not provide a regulatory statement or consult on the proposed Code change. The Authority considers that five of the 15 proposals in this year’s Code Review Programme are technical and non-controversial and has not provided a regulatory statement for them. Although the Authority is not required to consult on the technical and non-controversial changes, it invites comment on all proposals in the 2016 Code Review Programme.

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

How to make a submission

1.5 Please send your submission (using Microsoft Word in the format shown in Appendix A) by email to submissions@ea.govt.nz with ‘Consultation Paper— ‘ in the subject line.

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

<table>
<thead>
<tr>
<th>Postal address</th>
<th>Physical address</th>
</tr>
</thead>
<tbody>
<tr>
<td>Submissions</td>
<td>Submissions</td>
</tr>
<tr>
<td>Electricity Authority</td>
<td>Electricity Authority</td>
</tr>
<tr>
<td>PO Box 10041</td>
<td>Level 7, ASB Bank Tower</td>
</tr>
<tr>
<td>Wellington 6143</td>
<td>2 Hunter Street</td>
</tr>
<tr>
<td></td>
<td>Wellington</td>
</tr>
</tbody>
</table>

1.7 Please deliver your submissions by 5pm on 29 November 2016.

1.8 We will acknowledge receipt of all submissions electronically. If you do not receive electronic acknowledgement of your submission within two business days, please contact the Submissions’ Administrator.

All submissions will be published

1.9 Please note the Authority publishes all submissions. If there is part of your submission you do not want us to publish, please:

(a) indicate which part you do not want us to publish
(b) explain why you do not want us to publish it
(c) provide a version of your submission that we can publish (if we agree not to publish the full submission).

1.10 If you tell us there is part of your submission you do not want us to publish, we will talk to you before deciding whether we will publish that part.

1.11 However, please note that under the Official Information Act 1982, any person can request copies of submissions we receive, including any parts that we do not publish. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult you before releasing any material that you did not want us to publish.
2 Code Review Programme 2016

This is the second Code review programme

2.1 This paper presents the second set of ‘omnibus’ changes to the Electricity Industry Participation Code 2010 (Code) as the Code Review Programme 2016.

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

2.3 The purpose of the changes is to simplify language and processes, and make it easier for participants to understand how Code obligations affect them.

2.4 Each of the Code change proposals has merit but, because of competing priorities for resources, the Authority has not been able to include them in its annual work programme. The Authority considers that the ‘omnibus’ approach allows it to use its resources efficiently, and that the Code will benefit from improvements that might not otherwise have been possible.

The proposals are set out in Appendix B

2.5 The 15 Code change proposals are set out in Appendix B. Because each proposal is discrete from the others, the Authority has described and analysed each one separately. This means the format of this consultation paper is different from the consultation papers the Authority usually publishes.

2.6 For each proposed amendment, we have set out the problem definition and the proposed solution (including proposed Code drafting for some). For each proposal there is a separate assessment against the Authority's statutory objective, section 32(1) of the Act, and the Authority’s Code amendment principles.

2.7 For ten of the fifteen Code change proposals the paper includes a regulatory statement. The regulatory statement explains the objectives of the proposed amendment, and contains an evaluation of the costs and benefits of the proposed amendment and an evaluation of alternative means for achieving the proposed amendment.

2.8 For the remaining five amendments the Authority does not consider that a regulatory statement is required because the nature of the proposed change comes within the scope of section 39(3) of the Electricity Industry Act. For those five amendment proposals, the paper includes a short explanation of why the Authority has not prepared a regulatory statement.

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

2.10 Where a proposal results in few Code changes, the draft changes are shown in Appendix B. If the proposal would result in substantial drafting changes, the changes are shown in separate sections within Appendix C.

2.11 Most proposed amendments address a discrete issue, although because drafting changes affect most Parts of the Code, in some places changes intersect or overlap. Because each proposal stands on its own, some may proceed while others do not. Showing the draft changes separately allows submitters to assess how each proposed amendment would affect Code obligations.
2.12 The table below shows the list of topics addressed by each proposed amendment.

<table>
<thead>
<tr>
<th>Reference number</th>
<th>Topic</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016-01</td>
<td>Clarifying the use of the term ‘rules’</td>
<td>11</td>
</tr>
<tr>
<td>2016-02</td>
<td>Removing Part 6 and Part 9 exceptions</td>
<td>14</td>
</tr>
<tr>
<td>2016-03</td>
<td>Simplifying the requirements for certification and declaration</td>
<td>20</td>
</tr>
<tr>
<td>2016-04</td>
<td>Removing the definition of ‘assumed value of coefficient’</td>
<td>29</td>
</tr>
<tr>
<td>2016-05</td>
<td>Removing reference to the Authority acting reasonably</td>
<td>32</td>
</tr>
<tr>
<td>2016-06</td>
<td>Correcting the requirement to enter removal date in the registry</td>
<td>39</td>
</tr>
<tr>
<td>2016-07</td>
<td>Reassigning market administrator functions</td>
<td>42</td>
</tr>
<tr>
<td>2016-08</td>
<td>Relocating transition provisions</td>
<td>45</td>
</tr>
<tr>
<td>2016-09</td>
<td>Changing how Transpower makes grid information available</td>
<td>47</td>
</tr>
<tr>
<td>2016-10</td>
<td>Simplifying references to time</td>
<td>55</td>
</tr>
<tr>
<td>2016-11</td>
<td>Rationalising references to ‘registry’ and ‘registry manager’</td>
<td>62</td>
</tr>
<tr>
<td>2016-12</td>
<td>Simplifying terms about electricity supply</td>
<td>64</td>
</tr>
<tr>
<td>2016-13</td>
<td>Amending the definition of ‘information system’</td>
<td>69</td>
</tr>
<tr>
<td>2016-14</td>
<td>Amending the definition of ‘publish’</td>
<td>74</td>
</tr>
<tr>
<td>2016-15</td>
<td>Simplifying the meaning of ‘notify’</td>
<td>81</td>
</tr>
</tbody>
</table>
3 Regulatory Statements for the proposed amendments

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

3.2 The primary economic benefit described in the regulatory statements is a reduction in transaction costs across the industry, which is a productive efficiency benefit. Having said this, by improving the clarity and predictability of the Code, the proposed amendments could also deliver dynamic efficiency benefits. A clear, predictable and up-to-date set of industry rules is good regulatory practice. It is expected to facilitate increased participation in the electricity markets. This in turn might be expected to facilitate all three limbs of the Authority’s statutory objective, and provide both static and dynamic efficiency benefits to the economy.¹

3.3 When assessing the benefits and costs of Code amendment proposals, the Authority typically uses a real discount rate of 6% with sensitivities of plus or minus 2%. For the Code Review Programme 2015, the Authority has used a point estimate of the discount rate, for ease of analysis. To minimise the risk of overstating the net benefit of a proposal, the Authority has used a real discount rate of 8%.

¹ Static economic efficiency benefits can be broken down into allocative and productive efficiency benefits. Allocative efficiency is achieved when the marginal value consumers place on a product or service equals the cost of producing that product/service, so that the total of individuals’ welfare in the economy is maximised.

Productive efficiency is achieved when products and services that consumers desire are produced at minimum cost to the economy. That is, the costs of production equal the minimum amount necessary to produce the output. A productive efficiency loss results if the costs of production are higher than this, because the additional resources used could instead be deployed productively elsewhere in the economy.

Dynamic efficiency is achieved by firms having appropriate (efficient) incentives to innovate and invest in new products and services over time. This increases their productivity, including through developing new processes and business models, and lowers the relative cost of products and services over time.
## Appendix A  Format for submissions

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

<table>
<thead>
<tr>
<th>Reference</th>
<th>2016 -</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Question 1:</strong> Do you agree with the Authority's problem definition? If not, why not?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Question 2:</strong> Do you agree with the Authority's proposed solution? If not, why not?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Question 3:</strong> Do you have any comments on the Authority’s proposed Code drafting?</td>
<td></td>
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<td></td>
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<tr>
<td><strong>Question 4:</strong> Do you agree with the objectives of the proposed amendment? If not, why not?</td>
<td></td>
</tr>
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<td></td>
<td></td>
</tr>
</tbody>
</table>
| Question 5: Do you agree the benefits of the proposed amendment outweigh its costs?  
If not, why not?                                                                                                                                 |
<table>
<thead>
<tr>
<th></th>
</tr>
</thead>
<tbody>
<tr>
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</tbody>
</table>
| Question 6: Do you agree the proposed amendment is preferable to the other options?  
If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.                                                                 |
|                                                                                                                                                                                                   |
Appendix B  Proposed Amendments
### 2016-01 Clarifying use of the term ‘rules’

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 01 Clarifying use of the term ‘rules’</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem definition</td>
<td>The Code defines ‘Rules’ to mean the Electricity Governance Rules 2003. But in a few places the word ‘rules’ is used to mean something other than the EGRs. It could be confusing to use the same term to mean a number of different things. It is also preferable and best drafting practice to ensure that, where possible, defined terms are used only in accordance with their defined meaning.</td>
</tr>
<tr>
<td>Proposal</td>
<td>The Authority proposes to replace the term ‘rules’ with another term in each place where it does not refer to the EGRs.</td>
</tr>
</tbody>
</table>
| Proposed Code amendment | **6.3 Distributors must make information publicly available**  
(1) The purpose of this clause is to require each distributor to make certain information publicly available to enable the approval of distributed generation under Schedule 6.1.  
(2) Each distributor must make publicly available, free of charge, from its office and Internet site,—  
...  
(d) a statement of the policies, rules, or conditions under circumstances in which distributed generation will be, or may be, curtailed or interrupted from time to time in order to ensure that the distributor’s other connection and operation standards are met; and  
...  
**10.2 Authority’s and market administrator’s discretion and powers**  
(1) A clause in this Part that gives the Authority or market administrator a discretion or power—  
(a) confers an absolute discretion, subject to the Authority or the market administrator, as the case may be,—  
(i) taking into account any specific requirements set out in the clause; and  
(ii) observing the rules requirements of natural justice; and  
...  
**Schedule 12.4**  
5 Identification of Nodes and Links as Connection or Interconnection Nodes and links are identified as connection nodes or connection links or interconnection nodes or interconnection links according to the following rules:  
...  
35 Transmission Alternatives  
(4) If a transmission alternative service substitutes for both connection assets and interconnection assets, the allocation of the costs of the transmission alternative service as between connection assets and interconnection assets must be calculated in accordance with is made according to the rules set out in clause 25(2) for shared connection assets at an interconnection node. |
Cross heading above clause 13.135

Rules governing the preparation of provisional, interim, and final prices

Schedule 13.5

Requirements for FTR allocation plan

3 Requirements for FTR auction design

... 

(3) The FTR allocation plan must include FTR auction procedures rules.

<table>
<thead>
<tr>
<th>Grounds for not consulting</th>
<th>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no impact on current practice. Rather, the proposed amendment would improve the clarity of the language used in the Code.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assessment of proposed Code amendment against section 32(1) of the Act</td>
<td>The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Clarifying the correct use of the term ‘rules’ will reduce confusion, and lead to improved operational efficiency. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment would not affect competition or reliability.</td>
</tr>
<tr>
<td>Assessment against Code amendment principles</td>
<td>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</td>
</tr>
<tr>
<td>Principle 1: Lawfulness.</td>
<td>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.</td>
</tr>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not practicable to quantify the benefits of this amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
## 2016-02 Removing Part 6 and Part 9 exceptions

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 02 Removing Part 6 and Part 9 exceptions</th>
</tr>
</thead>
</table>
| **Problem definition** | Section 34 of the Act required the initial Code to include, among other things, a consolidation of enactments that included:  
  - Part 2 of the Electricity Governance Regulations 2003 (included as Part 3 of the Code);  
  - the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (included as Part 6 of the Code); and  
  - the Electricity Governance (Security of Supply) Regulations 2008 (included as Part 9 of the Code).  
  Section 34 of the Act also required the initial Code to include only those changes to the text of the enactments that were necessary or reasonably required to ensure that the Code—  
  - was consistent with the Act, the regulations, and any amendments made to other enactments by the Act; and  
  - was accurate and coherent; and  
  - addressed any transitional issues.  
  These restrictions on amending the enactments that comprised the initial Code were a transitional provision. The restrictions were meant to minimise any changes to the enactments made during the drafting of the Code and prior to the Authority coming into existence.  
  The requirements meant various clauses in Part 3 of the initial Code could not require market operation service providers to meet certain obligations in Parts 6 and 9 of the Code. That restriction appears in exceptions to clauses 3.2, 3.4, 3.11, 3.13, 3.14, 3.15 and 3.17.  
  The exceptions affect market operation service providers' obligations to self-review under clauses 3.13 and 3.14 and to arrange an audit of their software under clause 3.17. The exceptions also affect market operation service providers' entitlement to disclose information to the Authority under clause 3.11, and the ability of the Authority to review market operation service providers' performance under clause 3.15.  
  The Authority considers that removing the exceptions in Part 3 will better promote the efficient operation of the electricity industry. |
| **Proposal** | The Authority proposes that clauses 3.2, 3.4, 3.11, 3.13, 3.14, 3.15 and 3.17 place the same obligations on market operation service providers in relation to Parts 6 and 9 of the Code as for all other Parts of the Code. |
Amend the Code as follows:

### 3.2 Functions, rights, powers, and obligations of market operation service providers

A **market operation service provider** has the functions, rights, powers, and obligations set out in relation to that **market operation service provider** under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**.

### 3.4 Terms of market operation service provider agreements

1. The remuneration of a **market operation service provider** is as agreed between the **Authority** and the **market operation service provider**.

2. The **Authority** and the **market operation service provider** may agree on any other terms and conditions, not inconsistent with the functions, rights, powers, and obligations of that **market operation service provider** under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**.

### 3.11 Disclosure to Authority

Each **market operation service provider** is entitled to disclose to the **Authority** all information received by it from any person as part of its provision of services under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**.

### 3.13 Self-review must be carried out by market operation service providers

1. Each **market operation service provider** must conduct, on a monthly basis, a self-review of its performance.

2. The review must concentrate on the **market operation service provider**’s compliance with—
   - (a) its obligations under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**; and
   - (b) the operation of this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**; and
   - (c) any performance standards agreed between the **market operation service provider** and the **Authority**; and
   - (d) the provisions of the **market operation service provider agreement**.

### 3.14 Market operation service providers must report to Authority

1. Each **market operation service provider** must, within 10 working days after the end of each calendar month, provide a written report to the **Authority** on the results of the review carried out under clause 3.13.
(2) The report must contain details of—
(a) any circumstances identified by the market operation service provider in which it has failed, or may have failed, to comply with its obligations under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act; and
(b) any event or series of events that, in the market operation service provider's view, highlight an area where a change to this Code may need to be considered; and
(c) any other matters that the Authority, in its reasonable discretion, considers appropriate and asks the market operation service provider, in writing within a reasonable time before the report is provided, to report on.

3.15 Review of market operation service providers
(1) At the end of each financial year, the Authority may review the manner in which each market operation service provider has performed its duties and obligations under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act.
(2) The review must concentrate on the market operation service provider’s compliance with—
(a) its obligations under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act; and
(b) the operation of this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act; and
(c) any performance standards agreed between the market operation service provider and the Authority; and
(d) the provisions of the market operation service provider agreement.

3.17 Market operation service provider must arrange audit of software
(1) Unless otherwise agreed by the Authority in writing, each market operation service provider must arrange and pay for a suitably qualified independent person approved by the Authority to carry out—
(a) before any software is first used by the market operation service provider in connection with this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act, an audit of all software and software specifications to be used by the market operation service provider; and
(b) an annual audit of all software used by the market operation service provider, within 1 month after 1 March in each year; and
(c) an audit of any changes to the software or the software specification, before it is used by the market operation service provider.
A market operation service provider must ensure that the person carrying out an audit under subclause (1) provides a report to the Authority as to—

(a) the performance (including likely future performance) of all of the software in accordance with the relevant software specification; and

(b) any other matters that the Authority requires.

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

• facilitate the disclosure of information by market operation service providers to the Authority under clause 13.11;

• facilitate the accountability of market operation service providers, via the self-review requirements under clauses 3.13 and 3.14, and review by the Authority under clause 13.15;

• facilitate the auditing of software used by market operation service providers to fulfil their obligations in relation to Parts 6 and 9 under clause 13.17.

Accordingly, the proposed amendment is desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment is expected to have little or no effect on competition and reliability.

<table>
<thead>
<tr>
<th>Assessment against Code amendment principles</th>
</tr>
</thead>
</table>
| The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.

**Principle 1:** Lawfulness.

The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act.

**Principle 2:** Clearly Identified Efficiency Gain or Market or Regulatory Failure

The proposed amendment is consistent with principle 2 because it is expected to facilitate disclosure of information by market operation service providers to the Authority and to facilitate the accountability of market operation service providers for their service provision, including that their software performs as specified.

**Principle 3:** Quantitative

It is not practicable to quantify the benefits of this amendment. Accordingly, a quantitative analysis has not been undertaken.
<table>
<thead>
<tr>
<th>Assessment</th>
<th>Please refer to the qualitative cost-benefit analysis below.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regulatory Statement</strong></td>
<td>The objective of the proposal is to facilitate the accountability of market operation service providers for their service provision and to facilitate the disclosure of information by market operation service providers to the Authority.</td>
</tr>
<tr>
<td><strong>Objectives of the proposed amendment</strong></td>
<td>The Authority considers that the expected net benefit of the proposal is positive, for the reasons set out below.</td>
</tr>
<tr>
<td><strong>Evaluation of the costs and benefits of the proposed amendment</strong></td>
<td>Costs</td>
</tr>
<tr>
<td></td>
<td>Removing the exceptions does not place additional obligations on the current market operation service providers in relation to Part 6 of the Code. The references to market operation service providers in Part 6 are:</td>
</tr>
<tr>
<td></td>
<td>1) Two references to the system operator:</td>
</tr>
<tr>
<td></td>
<td>a. in clause 11(3)(p) of Schedule 6.1 ('any other information that is required by the system operator')</td>
</tr>
<tr>
<td></td>
<td>b. in clause 21(2)(b)(iia) of Schedule 6.2 ('the failure arises from an interruption in the conveyance of electricity in the distribution network, if the interruption was at the request of the system operator or under a nationally or regionally co-ordinated response to an electricity shortage')</td>
</tr>
<tr>
<td></td>
<td>2) Two references to the registry, only one of which is a reference to the market operation service provider:</td>
</tr>
<tr>
<td></td>
<td>a. in clause 15(1)(c) of schedule 6.2 ('without notice, if the trader that is recorded in the registry as being responsible for the ICP to which the distributed generation is connected to the distribution network has de-energised the ICP and advised the registry that the ICP has a status of ‘inactive’ with the reason of ‘de-energised – ready for decommissioning’).</td>
</tr>
<tr>
<td></td>
<td>Removing the exceptions would place additional obligations on one of the current market operation service providers in relation to Part 9 of the Code. The system operator would have monthly self-review and reporting obligations under clauses 3.13 and 3.14 respectively, and software audit obligations under clause 3.17.</td>
</tr>
<tr>
<td></td>
<td>However, the system operator already reports to the Authority on its security of supply activities on a monthly basis, as it would if required to comply with clauses 3.13 and 3.14. The system operator’s annual</td>
</tr>
</tbody>
</table>
self-review also includes material about the system operator’s security of supply activities. The software specification referred to in clause 3.17 names only the scheduling, pricing and dispatch software and the reserve management tool as auditable software. So the proposed Code amendment would not increase the system operator’s obligations under clause 3.17.

The main cost of the proposal is therefore the additional effort for the system operator to include any compliance-related and performance-related information in its monthly reports to the Authority on the system operator’s security of supply activities.

However, the Authority considers this additional effort will be negligible if the system operator continues to comply with its security of supply obligations under the Code, the Act and its service provider agreement.

Benefits

The main benefit of the proposal is facilitating market operation service providers’ accountability for their performance under Parts 6 and 9. The proposed Code amendment is expected to provide greater certainty that market operation service providers perform any Code obligations under Parts 6 and 9 to the same level as they do under other parts of the Code.

Net benefit

Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.

Evaluation of alternative means of achieving the objectives of the proposed amendment

The Authority could continue with the status quo arrangements. As noted above, the system operator reports to the Authority each month on its security of supply activities. However, the status quo does not facilitate market operation service providers’ accountability for meeting their Code requirements to the same extent as the proposed Code amendment would. Further, to the extent that the objectives of the proposed amendment can be achieved under the status quo, it is less certain they will be achieved.
## Problem definition

The Code includes a number of provisions that require participants to either certify, or declare, to the Authority that certain matters are true. Specifically:

- clause 9.29 requires that each retailer must provide the Authority with a statutory declaration that the retailer's customer compensation scheme complies with Subpart 4 of Part 9, and that the retailer has provided compensation to its qualifying customers to the extent required by the subpart.
- clause 12.35 provides that if consultation on a proposed transmission agreement is required, the parties to the transmission agreement must certify in writing to the Authority that they have consulted with affected end use customers.
- clause 12.99 requires Transpower to ensure that an auditor provides a report to the Authority that certifies matters in relation to Transpower's application of the transmission pricing methodology.
- clause 12.128 provides that if consultation on the application of Part 12 in respect of specified interconnection circuit branches, the HVDC link, shunt assets, or interconnection assets is required, Transpower and the relevant designated transmission customer must certify to the Authority that they have consulted with all potentially affected end use customers, and that there are no material unresolved issues affecting the interests of those customers.
- clause 13.230 provides that each participant who has submitted information to the information system under clause 13.225 (which relates to information about options contracts, contracts for difference, fixed-price physical supply contracts, and risk management contracts) must provide a certificate in the form of a declaration to the Authority to verify that the information submitted was correct.
- clause 13.236F provides that a participant that has provided a spot price risk disclosure statement to the Authority must provide a certificate to the Authority verifying certain matters in respect of the statement.

The intent of each of the above requirements is to require the relevant participant to affirm that certain matters are true. However, the requirements under the clauses are different.

In particular:
• clause 9.29 requires a statutory declaration
• clauses 12.35, 12.99 and 12.128 each require the relevant participant to certify matters
• clause 13.230 requires a certificate in the form of a declaration
• clause 13.236F requires a certificate
• clauses 9.29, 13.230, and 13.236F specify how the declaration/certification must be made (ie, the form of the declaration/certification and who must sign it), whereas clauses 12.35, 12.99 and 12.128 do not specify any such requirements
• clauses 9.29 and 13.230 provide that a declaration/certification must be given by two directors or the chief financial officer (or equivalent) or the chief executive officer (or equivalent), whereas clause 13.236F provides that a declaration/certificate must be given by one director and either another director, the chief financial officer (or equivalent), or the chief financial officer (or equivalent).

The Authority wishes to align these requirements. Where a participant must affirm that information is correct, the same standard should apply in each case, and the requirement should be for a participant to provide a certification.

There is little real difference between requiring two senior officers of a participant to certify matters, and requiring that those officers make a statutory declaration. Both require the officers to turn their minds to their accountability for making sure that the information is accurate.

The Authority also proposes removing the requirement for a statutory declaration, which may necessitate having to visit a solicitor, Justice of the Peace or other person authorised to witness a declaration under the Oaths and Declaration Act 1957. The Authority considers that this should give more flexibility to arrange signing, which should be more administratively efficient for participants.

The Authority also proposes to amend the clauses where certification is required to provide that the certification must be given in the form specified by the Authority, and by two people – either two directors, a director and the chief executive (or equivalent), or a director and the chief financial officer (or equivalent).

If the nature of the information in question is such that less formality is required, the Authority proposes to amend the clauses to provide that the relevant participants are required to confirm in writing that the information is correct, rather than certify the correctness of the information.

The Code includes other clauses that refer to certificates and certifications that the Authority does not propose amending.

• Clause 12.50 requires Transpower or a participant to provide a certified true copy of any written agreement for connection to and/or use of the grid entered into before 28 June 2007. The
requirement to certify that a document is a true copy is different from the declaration/certification requirements described in the clauses referred to above, which require participants to declare or certify as to the accuracy of a matter or that they have done certain things (e.g., clause 12.128 requires certification that consultation has been carried out). Accordingly, the Authority considers that it is not necessary to amend clause 12.50.

- The Authority considers that no change is required to clause 12.99, because an auditor’s report needs to include the certification required by that clause and it not necessary to specify the manner of the certification.

- Clause 2(c) of the guarantee in Schedule 14A.2 refers to the clearing manager providing a certificate to a bank that certifies that the principal has failed to comply with certain obligations. Schedule 14A.4 sets out the form in which a particular certificate relating to a letter of credit must be given. The security bond in Schedule 14A.5 refers to written demands be delivered to the surety that certifies that the principal has failed to comply with certain obligations. However, as the requirement to give those certifications arises in a different context from the clauses set out above, the Authority does not propose amending those clauses.

The Code also uses the terms ‘certify’, ‘certified’ and ‘certification’ in relation to metering installations and reconciliation participants. However this should not be confusing because the use of those words in the each of clauses above has nothing to do with metering installations, metering components, or reconciliation participants complying with Schedule 15.1.

Clause 1.1(1) of the Code states that terms only have their defined meaning "unless the context otherwise required". In the case of each of the clauses described in this proposal, the context requires that "certification" has its normal/ordinary meaning rather than the defined meaning.

**Proposal**

The Authority proposes to amend clauses 9.29, 13.230, and 13.236F to:

- in each case require the relevant participant to provide a certification
- include identical provisions as to the requirements with which the certification must comply, including that a certification must be given in the form specified by the Authority, and by two people – one director and either another director, the chief executive (or equivalent), or the chief financial officer (or equivalent)
- make any consequential drafting changes.

The Authority also proposes deleting clause 9.29(4), which prohibits the Authority from requesting a declaration before 1 October 2011, as
The Authority proposes to amend clauses 12.35 and 12.128 to require the relevant participant to confirm in writing to the Authority the matters specified in the clause are true.

<table>
<thead>
<tr>
<th>Proposed Code amendment</th>
<th><strong>Clause 9.29</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Statutory-declaration Certification of compliance</strong></td>
<td></td>
</tr>
<tr>
<td>9.29 Each <strong>retailer</strong> must provide <strong>certification statutory declaration</strong></td>
<td></td>
</tr>
<tr>
<td>(1) Each <strong>retailer</strong> must provide the <strong>Authority</strong> with a declaration certify to the <strong>Authority</strong> confirming that—</td>
<td></td>
</tr>
<tr>
<td>(a) its the <strong>retailer's customer compensation scheme</strong> complies with this subpart; and</td>
<td></td>
</tr>
<tr>
<td>(b) it the <strong>retailer</strong> has provided compensation to its <strong>qualifying customers</strong>, to the extent required by this subpart.</td>
<td></td>
</tr>
<tr>
<td>(2) The <strong>certification declaration</strong> provided under subclause (1) must be—</td>
<td></td>
</tr>
<tr>
<td>(a) a statutory declaration; and</td>
<td></td>
</tr>
<tr>
<td>(b) in the form specified by the <strong>Authority</strong>; and</td>
<td></td>
</tr>
<tr>
<td>(c) signed and dated by a director of the <strong>retailer</strong> and either —</td>
<td></td>
</tr>
<tr>
<td>(i) 2 directors another director of the <strong>retailer</strong>; or</td>
<td></td>
</tr>
<tr>
<td>(ii) the <strong>retailer's chief financial officer</strong>, or a person holding an equivalent position; or</td>
<td></td>
</tr>
<tr>
<td>(iii) the <strong>retailer's chief executive officer</strong>, or a person holding an equivalent position.</td>
<td></td>
</tr>
<tr>
<td>(3) A <strong>retailer</strong> must provide certifications declarations as follows:</td>
<td></td>
</tr>
<tr>
<td>(a) within 7 months of the end of a <strong>public conservation period</strong>;</td>
<td></td>
</tr>
<tr>
<td>(b) subject to subclause (4), within 1 month of receiving a request to do so by the <strong>Authority</strong>.</td>
<td></td>
</tr>
<tr>
<td>(4) The <strong>Authority</strong> must not request a declaration under subclause (3)(b) before 1 October 2011.</td>
<td></td>
</tr>
</tbody>
</table>

| Clause 12.35 | |
| **Increased service levels and reliability** | |
| (1) This clause applies if— | |
| (a) a proposed **transmission agreement** is not consistent in all material respects with the **benchmark agreement** because it increases the service levels above those that would apply if the **benchmark agreement** applied in accordance with clauses 12.10 or 12.13; or | |
| (b) subject to clause 12.39, a proposed **transmission agreement** or other agreement between **Transpower** and a **designated transmission customer** increases the level of reliability above the **grid reliability standards** for a particular **grid injection point** or **grid exit point**. | |
| (2) If this clause applies, the parties to the proposed **transmission agreement** must certify confirm in writing to the **Authority** that they have consulted with affected end use customers in relation to the proposed service levels or the proposed increase in reliability, and any resulting price implications, and that there are no material unresolved issues affecting the interests of those end use customers. | |
Clause 12.128

(2) An agreement between Transpower and a designated transmission customer under this clause may not exclude the application of clause 12.118(1)(h) and must be conditional in all respects on—
(a) obtaining agreement from all other potentially affected designated transmission customers that this Part does not apply to the specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer; and
(b) Transpower and the designated transmission customer certifying confirming in writing to the Authority that they have consulted with all potentially affected end use customers on this Part not applying to the specified interconnection branches, circuit branches, the HVDC link, shunt assets or interconnection assets or the designated transmission customer, and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must notify the Authority as soon as practicable in the event that Transpower enters into an agreement with a designated transmission customer under this clause.

Clause 13.230

13.230 Certification of information

(1) Each participant who has submitted information to the information system in accordance with clause 13.225 in a particular year must provide, within 3 months of the end of the year, a certificate certifying that the information submitted was correct.

(2) The certificate provided under subclause (1) must be—
(a) in the form of a declaration; and
(b) in the form specified by the Authority; and
(c) signed and dated by a director of the participant and either—
(i) 2 directors another director of the participant; or
(ii) the participant’s chief financial officer, or person holding an equivalent position, of the participant; or
(iii) the participant’s chief executive officer, or person holding an equivalent position, of the participant.

Clause 13.236F

13.236F Certification of spot price risk disclosure statement

(1) A disclosing participant who has submitted a spot price risk disclosure statement in accordance with this subpart must provide a certificate certifying to the Authority—
(a) verifying that the board of the disclosing participant has considered
(i) every spot price risk disclosure statement submitted under this subpart by the disclosing participant in the period to which the certificate relates; and
(ii) the projected change in net cash flows from operating activities of the disclosing participant as a result of applying the stress test or stress tests that relate to each period to which each spot price risk disclosure statement relates; and
(b) certifying that the disclosing participant has provided to each of the disclosing participant’s customers who, in the period to which the certificate certification relates, has entered into or renewed a contract with the disclosing participant that results in any electricity supplied to the customer being determined directly by reference to the final price at a GXP, information to enable the customer to consider the outcomes of applying the stress test or stress tests to the customer.

(2) Each certificate certification must be submitted as follows:
   (a) in the case of the first certificate certification submitted by a disclosing participant, no later than the end of the fourth quarter following the quarter in which the first spot price risk disclosure statement is submitted by that disclosing participant (in which case the certificate certification must relate to every spot price risk disclosure statement made by the disclosing participant in the preceding quarters):
   (b) in the case of every subsequent certificate certification, no later than the end of the fifth quarter following the quarter in which the last certificate certification was submitted (in which case the certificate certification must relate to every spot price risk disclosure statement made by the disclosing participant since the last certificate certification was submitted).

(3) The certificate A Each certification provided submitted under subclause (2) must be—
   (a) in the form specified by the Authority; and
   (b) signed and dated by a director of the disclosing participant and either— 1 of the following:
      (i) another director of the disclosing participant; or:
      (ii) the disclosing participant’s chief executive officer, or person holding an equivalent position, of the disclosing participant; or:
      (iii) the disclosing participant’s chief financial officer, or person holding an equivalent position, of the disclosing participant.

13.236H Authority may require independent audit of spot price risk disclosure statement or certificate certification

(1) The Authority may, in its discretion, on the recommendation of the person appointed to receive and analyse spot price risk disclosure statements or on its own motion, require an audit of 1 or more of the following:
   (a) a spot price risk disclosure statement;
   (b) part of a spot price risk disclosure statement;
   (c) the information set out in the certification given certificate submitted under clause 13.236F.

(7) A disclosing participant subject to an audit under this clause must, on request from the auditor, provide the auditor with such information as the auditor reasonably requires in order to audit the spot price risk disclosure statement or the information set out in the certification given certificate submitted under clause 13.236F (as the case may be).

(9) The disclosing participant must ensure that the auditor produces an
Before the audit report is submitted to the Authority, any failure of the spot price risk disclosure statement or the information set out in the certification given certificate submitted under clause 13.236F (as the case may be) to comply with this subpart must be referred back to the disclosing participant for comment.

13.236I Payment of auditor's costs

(1) If an audit establishes, to the Authority's reasonable satisfaction, that a disclosing participant's spot price risk disclosure statement or the information set out in the certification given certificate submitted under clause 13.236F (as the case may be) has not complied with this subpart (whether or not the Authority appoints an investigator to investigate the alleged breach), the disclosing participant must pay the auditor's costs.

... (3) If an audit establishes to the Authority's reasonable satisfaction that a disclosing participant's spot price risk disclosure statement or the information set out in the certification given certificate submitted under clause 13.236F (as the case may be) has complied with this subpart, the Authority must pay the auditor's costs.

<table>
<thead>
<tr>
<th>Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act</th>
</tr>
</thead>
</table>
| The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. The proposed amendment to the Code would make the processes by which participants must affirm that certain matters are true more consistent, and appropriate to the circumstances. It would also make it easier for participants to understand, and to comply with, their obligations. This promotes the efficient operation of the electricity industry. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.
| The proposed amendment is not expected to affect competition in, or the reliable supply by, the electricity industry. |

<table>
<thead>
<tr>
<th>Assessment against Code amendment principles</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Principle 1: Lawfulness.</th>
</tr>
</thead>
<tbody>
<tr>
<td>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32 of the Act.</td>
</tr>
<tr>
<td>Principle 2:</td>
</tr>
<tr>
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</tr>
<tr>
<td>Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
</tr>
<tr>
<td>Principle 3:</td>
</tr>
<tr>
<td>Quantitative Assessment</td>
</tr>
<tr>
<td>Regulatory Statement</td>
</tr>
<tr>
<td>Objectives of the proposed amendment</td>
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<tr>
<td>Evaluation of the costs and benefits of the proposed amendment</td>
</tr>
<tr>
<td>Costs</td>
</tr>
</tbody>
</table>
**Benefits**

The primary benefit of the proposal is to make it easier and more cost effective for participants to comply with their Code obligations. For each clause of the Code proposed to be amended, the Authority anticipates the compliance cost faced by a participant would be either less than or equal to the cost they face now.

**Net benefit**

Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.

**Evaluation of alternative means of achieving the objectives of the proposed amendment**

The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.
## Problem definition

The defined term ‘assumed co-efficient of variation’ means ‘the value of co-efficient of variation that is set by the market administrator for the purpose of calculating the preliminary sample size’.

This definition is incorrect. The assumed co-efficient of variation is set in clause 2 of Appendix 2 of Schedule 15.5 of the Code, rather than being set by the market administrator. Therefore, a Code amendment would be required if a new assumed co-efficient of variation were desired.

The Authority also notes that this defined term is used only twice in the Code. Both references are in clause 2 of Appendix 2 of Schedule 15.5. This clause describes how the size of a preliminary sample is to be determined for the purpose of developing a profile under the Code.

The Authority considers that removing this definition and inserting its meaning in the above clause would improve the readability of the Code.

## Proposal

The proposal is to:

- remove the defined term ‘assumed co-efficient of variation’ from Part 1

- in clause 2 of Appendix 2 of Schedule 15.5, replace the references to ‘assumed co-efficient of variation’ with ‘value of co-efficient of variation’.

## Proposed Code amendment

### Part 1

#### 1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

\[ \text{assumed co-efficient of variation} \text{ means the value of co-efficient of variation that is set by the market administrator for the purpose of calculating the preliminary sample size} \]

Schedule 15.5

Profile administration

Appendix 2

Determining statistically sampled profiles

(4) In the above formula—
N is the size of the **profile population**

\( \alpha \) is the confidence level

\( z_\alpha \) is the value of the standard normal distribution which gives \( \alpha \) probability outside the tails

\( C_A \) is the **assumed value of co-efficient of variation** of the unit cost

\( r \) is the **relative standard error** of the unit cost.

(5) The following parameter values are to be used:

- **Assumed Value of co-efficient of variation** (\( C_A \)): 0.1
- **Relative standard error** (\( r \)): 0.05
- Confidence level (\( \alpha \)): 0.99

---

**Grounds for not consulting**

The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.

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

The proposed amendment would simplify the Code, which would make it easier for participants to understand and give effect to their obligations. This is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry.

Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment would not affect competition or reliability.

**Assessment against Code amendment principles**

The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.

**Principle 1: Lawfulness.**

The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.

**Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory**

The proposed amendment is consistent with principle 2 in that it addresses problems created by the existing Code, which require amendment to resolve, and that it is expected to result in participants operating more efficiently and incurring lower costs in complying with the Code.
<table>
<thead>
<tr>
<th>Failure</th>
<th>Principle 3: Quantitative Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
### 2016-05 Removing references to the Authority acting reasonably

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 05 Removing references to the Authority acting reasonably</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem definition</strong></td>
<td><strong>Provisions that require the Authority to act reasonably</strong>&lt;br&gt;Various clauses in the Code require the Authority to act reasonably.&lt;br&gt;As a Crown entity, the Authority is required to act in accordance with administrative law principles when exercising its powers and functions under the Code. These principles include a requirement to act reasonably.&lt;br&gt;Therefore, provisions in the Code that require the Authority to act reasonably are redundant, and the Authority considers that they can be deleted.&lt;br&gt;&lt;br&gt;<strong>Provisions that require the Authority to publish information within a ‘reasonable period of time’</strong>&lt;br&gt;Various clauses in the Code require the Authority to publish information within a ‘reasonable period of time’.&lt;br&gt;The Authority considers that the administrative law requirement to act reasonably covers the requirement to publish information or documents within a reasonable period of time. In addition, the Authority is under an administrative law obligation to carry out its functions without unreasonable delay.&lt;br&gt;Therefore, references to the Authority carrying out its functions ‘within a reasonable period of time’ can be deleted.&lt;br&gt;&lt;br&gt;<strong>Provisions that require the Authority to make ‘reasonable endeavours’</strong>&lt;br&gt;Various clauses in the Code require the Authority to make ‘reasonable endeavours’.&lt;br&gt;The term ‘reasonable endeavours’ is generally used in a commercial context, and imposes an obligation to act unless doing so would not be in the relevant person’s commercial interest. It is not appropriate for statutory obligations on a Crown entity like the Authority, and the Authority proposes to delete it.</td>
</tr>
<tr>
<td><strong>Proposal</strong></td>
<td>The Authority proposes to amend the Code to:&lt;br&gt;• remove requirements for the Authority to act reasonably&lt;br&gt;• remove requirements for the Authority to publish information within a reasonable period of time&lt;br&gt;• remove references to the Authority being required to make ‘reasonable endeavours’.</td>
</tr>
<tr>
<td><strong>Proposed</strong></td>
<td>1(1) Interpretation</td>
</tr>
<tr>
<td>Code amendment</td>
<td>undesirable trading situation means any situation—</td>
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<td>----------------</td>
<td>--------------------------------------------------</td>
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<tr>
<td></td>
<td>(a) that threatens, or may threaten, confidence in, or the integrity of, the wholesale market; and</td>
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<tr>
<td></td>
<td>(b) that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved…</td>
</tr>
</tbody>
</table>

3.14 Market operation service providers must report to Authority

…

(2) The report must contain details of—

…

(c) any other matters that the Authority, in its reasonable discretion, considers appropriate…

7.3 Functions of the system operator in relation to security of supply and emergency management

…

(6) If the system operator makes a departure under subclause (5), the system operator must provide a report to the Authority setting out the circumstances of the EMP departure situation and the actions taken to deal with it. The Authority must publish the report within a reasonable time of its receipt.

7.11 Review of performance of the system operator

…

(2) The self-review must contain such information as the Authority may reasonably require from time to time…

8.14 Departure from policy statement

…

(3) The Authority must publicise the report within a reasonable time after receiving it.

8.47 Departure from procurement plan

…

(3) The Authority must publicise the report within a reasonable time after receiving it.

8.63 Decision of the Rulings Panel

…

(4) The Authority must publish the Rulings Panel's decision as soon as reasonably practicable.

9.33 Payment of auditor’s costs
(1) If an audit establishes, to the Authority’s reasonable satisfaction…

(3) If an audit establishes to the Authority’s reasonable satisfaction…

10.8 Requirements for information to be recorded, given, produced, or received

…

(3) The Authority must act reasonably when determining the requirements referred to in subclause 1.

10.16 Metering data exchange timing and formats

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

(a) in the absence of any timeframe specified in this Code, within a reasonable timeframe notified by the Authority; and…

…

(2) The Authority must provide reasonable notice of any changes to the format notified under subclause (1)(b).

…

Schedule 10.2, clause 4 Scope of audits

An audit must address such matters as the Authority reasonably requires, having regard to the reasons for which the Authority considers that the audit is required, and any matters that arise during the audit.

Schedule 10.2, clause 10 Payment of auditor’s costs,

(1) If an audit establishes, to the Authority’s reasonable satisfaction,…

(2) If an audit establishes, to the Authority’s reasonable satisfaction,…

Schedule 10.3, clause 1(2)(b) Applications for approval and renewal of approval

(2) An applicant must—

…

(b) provide promptly any other information or documentation the Authority may reasonably request.

Schedule 10.7, clause 41 Certification stickers

(2) An ATH attaching a metering installation certification sticker must ensure that it shows—
any other information that the Authority may, from time to time, notify giving reasonable notice.

Schedule 10.7, clause 45 Category 1 metering installation inspection requirements

(3) A metering equipment provider must, before it carries out inspections under subclause (1)(b),—

(b) provide promptly any other information or documentation the Authority may reasonably request.

12.54 Obligations to provide information

(1) Each participant must provide information reasonably required by the Authority for the purposes of this subpart and respond to requests from the Authority under this subpart promptly and accurately.

13.7B Authority may request system operator to report on accuracy of forecasts of non-dispatch-capable load at conforming GXPs

(1) The Authority may, from time to time, request the system operator to report to the Authority on the accuracy of the forecast that it prepares under clause 13.7A(1).

(2) A request—

(b) must specify a reasonable date by which the system operator must provide the report...

13.27B Authority to determine conforming and non-conforming GXPs if requested

(1) Subclause (4) applies if—

(a) a purchaser or the system operator makes a request under clause 13.27H; and

(b) the Authority decides there are valid grounds to consider the request.

(4) The Authority must decide whether to proceed with the request within a reasonable time after receiving the request.

13.27D System operator to provide advice within reasonable time
The **system operator** must provide the advice requested under clause 13.27C(1)(b) within a **reasonable** time specified by the **Authority**.

### 13.232 Payment of costs relating to audits

1. If an **audit** establishes, to the **Authority's** reasonable satisfaction, …
2. If an **audit** establishes to the **Authority's** reasonable satisfaction that a disclosing participant’s spot price risk disclosure statement …

### 13.236I Payment of auditor's costs

1. If an **audit** establishes, to the **Authority's** reasonable satisfaction, …
2. If an **audit** establishes to the **Authority's** reasonable satisfaction that a disclosing participant’s spot price risk disclosure statement …

### 13.255 Authority may direct FTR manager to suspend allocation of FTRs

The **Authority** may direct the **FTR manager** to suspend the allocation of **FTRs** if there is any situation that—

...  

(b) in the **Authority's** reasonable opinion, cannot satisfactorily be resolved by any other mechanism available under this Code.

### Schedule 13.4

#### 5 Authority may require extra information

The **Authority** may require the provision of additional information at any stage during the application process and, if the Authority’s requirements are **reasonable**, the applicant must provide that information to the **Authority**.

### 9 Decision must be recorded

1. The **Authority** must keep a register of all current approvals granted under this Schedule available for public inspection free of charge during normal office hours at the offices of the **Authority** and on the **Authority's** website at all reasonable times.

### Schedule 13.7

#### 4 Data for most recent 12 months unavailable

1. If the data required under clauses 1 to 3 is not available for the most recent 12 consecutive months, the **Authority** must use reasonable endeavours to make a determination in accordance with the methodology set out in this Schedule using the data it has available.
2. If the available data is insufficient to enable the **Authority** to make a determination in accordance with subclause (1), the **Authority** must make a determination by—
   (a) using all available data; and
(b) using its own reasonable expectations of the future activities at the GXP; and

....

Schedule 13.8

12 Authority to keep register of all current approvals

....

(2) The Authority must keep the register available for public inspection free of charge—

....

(b) on its website, at all reasonable times.

Schedule 15.1

4 Obtaining certification

....

(2) The reconciliation participant must promptly provide other such information as the Authority may reasonably request.

12 Authority and participant requested audits

(1) If at any time the Authority reasonably considers that a participant may not have complied with a clause in this Part or Part 11, the Authority may audit the participant or appoint an auditor to carry out an audit.

13 Scope of audits

An audit must address such matters as the Authority reasonably requires, having regard to the reasons for which the Authority considers that the audit is required under clause 12, and any matters that arise during the audit.

<p>| Grounds for not consulting | The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. |
| Assessment of proposed Code amendment against section 32(1) of the Act | The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment would not affect competition or reliability. |
| Assessment against Code amendment principles | The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant. |
| Principle 1: | The proposed amendment is consistent with the Act, as discussed above |</p>
<table>
<thead>
<tr>
<th>Lawfulness.</th>
<th>in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not possible to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
2016-06 Correcting requirement to enter removal date in the registry

Reference No. | 2016-06 Correcting requirement to enter removal date in the registry

Problem definition | Clause 7 of Schedule 11.4 requires metering equipment providers (MEPs) to provide the registry with information in accordance with Table 1 of Schedule 11.4. An MEP must provide information for each metering installation for which it is responsible.

If an MEP removes a meter or a data storage device from a fully certified metering installation, the MEP is required by clause 7 of Schedule 11.4 to provide the registry with the removal date as shown in row 21 of Table 1 of Schedule 11.4.

This is an unnecessary obligation. Each time an MEP provides information to the registry, the MEP must provide the date from which the updated information applies. This is the ‘event date’. The date on which a meter or data storage device was removed from a metering installation can be determined by looking at the event date. Requiring MEPs to provide the removal date in addition to the event date is therefore unnecessary.

Recognising this, many MEPs do not provide the removal date.

Proposal | The Authority proposes to amend row 21 of Table 1 of Schedule 11.4 so providing a removal date is optional for a fully certified metering installation.

Proposed Code amendment | Table 1 of Schedule 11.4:

<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>removal date of a meter or data storage device</td>
<td>a date that a meter or data storage device is removed</td>
<td>Required</td>
<td>Optional for meter or data storage device</td>
</tr>
</tbody>
</table>

Assessment of proposed Code amendment against the Authority’s | The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Removing the unnecessary obligation on MEPs will lead to improved operational efficiency.

Accordingly, the amendment is also desirable to promote the efficient
| **objective and section 32(1) of the Act** | operation of the electricity industry in accordance with section 32(1)(c) of the Act.  
The proposed amendment would have no effect on competition or reliability. |
| **Assessment against Code amendment principles** | The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant. |
| **Principle 1: Lawfulness.** | The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32 of the Act. |
| **Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure** | The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve. |
| **Principle 3: Quantitative Assessment** | The costs of the proposed Code amendment can be readily quantified. However, it has not been practicable to quantify the benefits. Hence, a partial quantitative assessment of the proposed amendment’s costs and benefits has been undertaken (see below). |
| **Regulatory Statement** |  |
| **Objectives of the proposed amendment** | The objective of the proposal is to contribute to the efficient operation of the electricity industry by removing an unnecessary obligation on MEPs. |
| **Evaluation of the costs and benefits of the proposed amendment** | The Authority considers the proposed amendment would have a positive net benefit.  

*Costs*  
The Authority expects the proposed amendment would have a minor cost, associated with amending the registry. This is expected to be no more than $2,000.  
There will be no costs imposed on participants. This is because the proposed Code amendment would align the Code with industry practice.  

*Benefits*  
The primary benefit of the proposed amendment is that it would
<table>
<thead>
<tr>
<th>Evaluation of alternative means of achieving the objectives of the proposed amendment</th>
</tr>
</thead>
<tbody>
<tr>
<td>The only alternative would be the status quo, which would not achieve the objectives of the proposed amendment. The costs on MEPs from complying with the requirement in row 21 of Table 1 of Schedule 11.4 would result in no benefit, since the additional information is not required. The Authority is therefore satisfied that the proposed Code amendment is the best alternative.</td>
</tr>
</tbody>
</table>

remove an unnecessary cost on MEPs if the Authority were to enforce compliance with the requirement to provide certain information in accordance with row 21 of Table 1 of Schedule 11.4. The Authority expects that the cost for MEPs to comply with this requirement would far exceed the cost of amending the registry.

*Net benefit*

Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
### 2016-07 Reassigning the market administration obligations

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 07 Reassigning the market administration obligations</th>
</tr>
</thead>
</table>
| Problem definition | The Authority is responsible for various market administration obligations under the Code. This responsibility arises either in its role of industry regulator or in its role of market administrator. Over time, the number of obligations that the Code places on the market administrator function has fallen. The two primary reasons for this fall have been as follows:  
  • The former Electricity Commission, and then the Authority, have taken on these obligations under the role of industry regulator (eg, as occurred when the ‘New Part 10’ Code amendment was made in 2011).  
  • In 2007, the former Electricity Commission established the wholesale information and trading system (WITS) service provider, thereby removing this part of the market administrator function. The Authority considers the current arrangements for market administration could be more closely aligned with the Authority’s statutory objective. Specifically, the Authority believes moving accountability for some market administration Code obligations from the Authority to market operation services providers will promote the efficient operation of the electricity industry. |
| Proposal | The proposed Code amendment revises the current arrangements for market administration, as follows:  
  • The Authority keeps those market administration Code obligations that are most appropriate for the regulator.  
  • Market operation service providers will take over the remaining market administration Code obligations that they currently undertake on behalf of the market administrator. The proposed Code amendment will result in no Code obligations remaining with the market administrator. Accordingly, the Authority proposes to remove the definition of ‘market administrator’ from the Code. |
| Proposed Code amendment | Refer to the drafting schedule in Appendix C. |
| Assessment of proposed Code amendment | The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. It would reduce the Authority’s operational costs without increasing costs to market operation service provider. |
| against the Authority’s objective and section 32(1) of the Act | Accordingly, the proposed amendment is desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The Authority does not expect that the proposed amendment will affect competition or reliability. |
| Assessment against Code amendment principles | The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant. |
| Principle 1: Lawfulness. | The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act. |
| Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure | The proposed amendment is consistent with principle 2 since it is expected to result in the more efficient provision of market administration services. |
| Principle 3: Quantitative Assessment | The Authority has carried out a quantitative assessment of the proposal’s costs and benefits (see below). |
| Regulatory Statement | The objective of the proposal is to make contestable the market administration Code obligations that need not be undertaken by the Authority. |
| Objectives of the proposed amendment | The Authority considers that the proposed Code amendment would have a positive net benefit. |
| Costs | The Authority expects the proposed amendment will not place additional costs on the market operation service providers who are receiving market administration obligations. These service providers already undertake the obligations that will be transferred to them. |
| Benefits | The primary benefit of the proposed amendment is that it would |
reduce the Authority’s administrative costs. The Authority estimates this to be approximately $2,150 per annum,\(^2\) which equates to a present value of approximately $18,400 (assuming a 15-year discount period and a real discount rate of 8%).

**Net benefit**

Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.

<table>
<thead>
<tr>
<th>Evaluation of alternative means of achieving the objectives of the proposed amendment</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Authority could competitively tender the market administrator role currently described in the Code.</td>
</tr>
<tr>
<td>There appear to be three main drawbacks with this alternative option compared with the proposed amendment.</td>
</tr>
<tr>
<td>Firstly, other market operation service providers can undertake certain market administrator obligations more efficiently than can the market administrator.</td>
</tr>
<tr>
<td>Secondly, this alternative would result in higher tendering costs than under the proposal, from the Authority undertaking an additional request for tender.</td>
</tr>
<tr>
<td>Thirdly, this alternative would result in the Authority incurring costs overseeing the market administrator service provider’s performance (eg, contract management).</td>
</tr>
</tbody>
</table>

A refinement to the first alternative would be for the Authority to remove from the market administrator role those Code obligations that other market operation service providers undertake more efficiently. This would leave a market administrator role with a wide scope of responsibilities but requiring only a very small amount of resources (estimated at less than 0.5 full time equivalents). It may therefore not be worthwhile tendering the role, given the additional cost of doing so.

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\(^2\) Relating primarily to staff time and costs.
2016-08  Relocating transition provisions

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>Relocating transition provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem definition</td>
<td>Part 17 of the Code contains transitional provisions. Most relate to the transition from the arrangements that were in place immediately before the Code came into effect, to the arrangements in place under the Code. The usual drafting approach for amendments made after the Code came into effect, if a period of transition is required, is to locate the transition provisions in the Part of the Code affected by the amendment. For example, clause 6.13 provides for transition in relation to the changes made by Electricity Industry Participation Code Amendment (Distributed Generation) 2014; and clause 10.51 provides for transition in relation to the changes made by the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2). There are two exceptions to this approach: transitional provisions in relation to the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, and transitional provisions in relation to the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013. The transitional provisions for those two amendments are in Part 17. The Authority considers that it is likely to be confusing for users of the Code if the approach to transition provisions is inconsistent. Further, it is more difficult for uses if some provisions are in one Part of the Code while others are in another Part. As for the transition provisions in relation to settlement and security, these have now expired.</td>
</tr>
<tr>
<td>Proposal</td>
<td>The Authority proposes to move clauses 17.48A and 17.48B, which relate to the extended reserve arrangements, from Part 17 to Part 8. The Authority proposes delete expired clauses 17.210A to 17.210O, which related to settlement and prudential security.</td>
</tr>
<tr>
<td>Proposed Code amendment</td>
<td>Refer to the drafting schedule in Appendix C.</td>
</tr>
<tr>
<td>Grounds for not consulting</td>
<td>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</td>
</tr>
<tr>
<td>Assessment of proposed Code</td>
<td>The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity</td>
</tr>
</tbody>
</table>
amendment against section 32(1) of the Act

industry.

Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment would not affect competition or reliability.

<table>
<thead>
<tr>
<th>Assessment against Code amendment principles</th>
<th>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 1: Lawfulness.</td>
<td>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.</td>
</tr>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not possible to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
## 2016-09 Changing how Transpower makes grid information available

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>Problem definition</th>
</tr>
</thead>
</table>
| 2016 - 08 Changing how Transpower makes grid information available | **Background**  
The Interconnection Asset Capacity and Grid Configuration document allows participants to see what interconnection assets Transpower must make available, how they are configured, and at what capacity. The document includes:  
(a) a diagram showing the configuration of the national grid and the capacity of Transpower’s grid assets, other than its connection assets;  
(b) a document titled ‘Interconnection Branch Report’, which includes text boxes that set out service measures and service levels that relate to different circuit branches, which is date stamped 1 July 2009;  
(c) a document titled ‘Configuration and capacity of the HVDC link’ (effective from 30 June 2009);  
(d) a document titled ‘Service measures and levels for shunt assets’, dated 30 June 2009;  
(e) a document titled ‘Service measures and levels for HVDC shunt assets’, dated 30 June 2009; and  
(f) a page headed ‘Date for summer and winter periods’, which refers to rule 2.4.1 and 2.4.2 and which is dated 30 June 2009.  
The grid configuration document was originally a schedule to the Electricity Governance Rules. It continues in force by virtue of clause 12.106(1) of the Code.  
The grid configuration is incorporated by reference into the Code under clause 12.110. |

**Processes for amending the grid configuration are not flexible enough**  
The process for amending the grid configuration is not practical and is not flexible enough.  
Currently, by 30 November each year, Transpower must provide the Authority with updated information on the grid configuration document. The Authority consults on the document and decides whether to incorporate it by reference into the Code in accordance with section 32 and schedule 1 of the Electricity Industry Act 2010.  
Because this happens only once a year, and because it requires the Authority to complete some administrative steps before incorporating it into the Code, the grid configuration document can be out of date.
by the time the Authority publishes it. There is no process for amending the grid configuration document more than once a year.

The Authority considers the annual process for amending the grid configuration does not promote the efficient operation of the electricity industry as much as would a process not involving the grid configuration being incorporated by reference into the Code.

*Publishing grid configuration information is not timely enough*

Publishing information in the grid configuration once a year is not timely enough.

Transpower is required to report to the Authority by 30 November each year on the grid configuration. This report must reflect changes to interconnection asset capacities and the configuration of the grid during the 12 months to 30 June of that year.

The Authority considers that the annual publication of information on these matters does not promote efficient supply, consumption and investment decisions by transmission grid users and their customers as much as would more frequent publication.

*The Authority does not need to specify the form in which information is provided*

The Authority considers that it does not need to specify the form in which the grid configuration is provided, or the form in which information about the capacities of individual interconnection assets must be provided.

Clause 12.107(2) requires Transpower to provide the grid configuration in the form specified by the Authority. Clause 12.116(2)(c) also requires Transpower to provide information about the capacities of individual interconnection assets in the form determined by the Authority. The Authority considers this requirement to be unnecessary as it is sufficient to require only that Transpower publish the relevant information, taking into account the preferences of stakeholders.

*Reporting on compliance with the grid configuration is more costly than necessary*

The costs that Transpower incurs to report on its compliance with the grid configuration incorporated by reference into the Code are higher than necessary.

As noted above, currently Transpower must report to the Authority by 30 November each year on the grid configuration. This report must include the extent to which Transpower complied with the service levels in the grid configuration and kept the grid in the configuration set out in the grid configuration during the 12 month period ending at 30 June of that same year.

Transpower considers that its compliance costs would be reduced if it
instead followed a mandatory breach reporting process for any instances where it failed to comply with clause 12.111(1) or 12.111(2) and clause 12.112(1) did not apply.

The Authority proposes to amend the Code so that Transpower is responsible for publishing and updating the grid configuration. The Code would continue to require the grid configuration to contain the matters listed in clauses 12.107(4) and (5) of the Code.

However, the Authority would not review or consult on the grid configuration and would not incorporate it by reference into the Code.

The Authority considers that this approach would:
- reduce the administrative burden on the Authority;
- reduce the administrative burden on Transpower, by enabling Transpower to undertake more frequent, but less time-consuming, updates;
- make it easier for grid users and interested parties to access and review grid information, reducing the need for those parties to contact Transpower for information;
- reflect the Authority's view that Transpower is the appropriate party to make decisions about updating and amending the grid configuration.

Changes to grid configuration
Currently, clause 12.111(2) requires that Transpower keep the grid in the configuration set out in the published grid configuration document. The Authority proposes that this should not change.

Service levels and measures for interconnection assets
Currently, Transpower must make each interconnection circuit branch, interconnection transformer branch, shunt asset and the HVDC link in the grid configuration document available for use by the system operator at least at the service levels specified in the published grid configuration document.

This provision is not practicable. As soon as Transpower changes any service level (including for example changes for winter/summer line ratings) it breaches the requirements of the clause. A better approach is to remove the link to the published grid configuration document and instead refer only to the document prepared by Transpower.

Reporting on grid configuration, service levels and measures
Transpower is currently required to report to the Authority annually on the extent to which it complied with its obligations during the previous year. The purpose of the information that Transpower provides to the Authority about the extent to which it complied with its obligations is so that:
- grid users can monitor the capacity of interconnection assets
the Authority can assess Transpower's compliance with the overarching requirement under clause 12.111 of the Code that the grid is not changed.

Transpower has indicated that it intends to provide monthly updates to interested parties regarding the grid configuration, by publication on Transpower's website.

Accordingly, the Authority considers this should be reflected in the Code. The grid configuration document should include the information set out in clause 12.107(4) (which includes service levels and measures) for the previous month, as well as a diagram showing the current configuration of the grid.

The Authority considers that these updates would provide adequate monitoring of the grid configuration. The Authority proposes to amend the Code to remove Transpower's reporting requirements in relation to the grid configuration (apart from the reporting of breaches, which is discussed below). The Authority would not review or consult on the grid configuration as it currently does.

**Breaches**

The Authority considers it appropriate to require Transpower to report on breaches of its requirement to publish the monthly plan described above, and the requirement to keep the grid in the configuration and at the service levels set out in the grid configuration document.

**Information on capacities of individual interconnection assets**

Clause 12.116(2)(c) states that information about the capacities of individual interconnection assets that must be published under clause 12.116(1) must be published in the form determined by the Authority as soon as reasonably practicable after the Authority has determined the form. The Authority considers that this requirement is unnecessary as it is sufficient to require only that Transpower publish that information. The requirement can consequently be removed from the Code.

Proposal

The Authority proposes to amend Part 12 of the Code so that:

- the grid configuration would no longer be incorporated by reference into the Code
- Transpower would become responsible for publishing the grid configuration in a form that Transpower considers suitable and taking into account the requirements of its customers and other relevant stakeholders
- Transpower would publish monthly updates on the grid configuration
- Transpower would report breaches related to the grid configuration as and when the breaches occur, rather than
Specifically, the Authority proposes to amend the Code to:

- revoke clause 12.106, which refers to the grid configuration that was set out in the Electricity Governance Rules continuing in force;
- revoke clause 12.110, which refers to the grid configuration being incorporated by reference into the Code;
- remove the requirements for the Authority to set the form of, review, consult on, and decide on the grid configuration (see clauses 12.107(2), (3), and (6), 12.108, 12.109 and 12.118(3))
- insert a new clause 12.107(1A) to require Transpower to publish monthly updates on the grid configuration and to indicate any changes as at the end of the previous month
- amend clauses 12.107, 12.111 and 12.112 by adding a requirement that Transpower report breaches or possible breaches
- revoke clause 12.116(2)(c)
- remove the requirements for Transpower to report annually on its compliance with the grid configuration, on agreements it has entered into under clauses 12.128 and 12.151, and on an updated grid configuration (see clauses 12.118(1)(b) to (f) and 12.118(1)(h) to (i))
- make consequential drafting changes and improvements.

The Authority considers this approach would:

- reduce the administrative burden on the Authority;
- reduce the administrative burden on Transpower, by enabling Transpower to undertake more frequent, but less time-consuming, updates;
- make it easier for grid users and interested parties to access and review grid information, reducing the need for those parties to contact Transpower for information;
- reflect the Authority’s view that Transpower is the appropriate party to make decisions about amending the grid configuration.

### Proposed Code amendment

Refer to the drafting schedule in Appendix C.

### Assessment of proposed Code amendment against the Authority’s objective

The proposed amendment is consistent with the Authority’s objective because it would contribute primarily to the efficient operation of the electricity industry.

The proposed amendment would promote the efficient operation of the electricity industry, by:

- reducing administrative costs for the Authority and Transpower;
Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment is not expected to have a major effect on competition in, or the reliable supply by, the electricity industry. There may be some benefits for competition and/or reliable supply, from participants being able to more easily assess the current grid configuration. This might be expected to promote efficient supply, consumption and investment decisions by transmission grid users and their customers. However, any such improvements in competition and/or reliable supply are expected to have a second order effect.

The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.

<table>
<thead>
<tr>
<th>Principle 1: Lawfulness.</th>
<th>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 as it is expected to result in Transpower and the Authority incurring lower administration costs, and participants facing lower costs when accessing and reviewing grid configuration information.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>The Authority has carried out a quantitative assessment of the proposal’s costs and benefits (see below).</td>
</tr>
</tbody>
</table>

The objective of the proposal is to improve the timeliness of published information on the configuration of the national transmission grid, and the efficiency with which that information is provided.

The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below.
The Authority does not expect the proposed amendment to place additional costs on industry participants.

**Benefits**

The primary benefits of the proposal are:

- to reduce Transpower’s and the Authority’s administrative costs relating to maintaining the grid configuration document; and
- to make it easier for grid users and interested parties to access and review grid configuration information.

The key change under the proposed amendment is that Transpower would no longer be required to provide the grid configuration to the Authority annually. Instead, Transpower would publish on Transpower’s website a monthly update on grid capacity and configuration information, indicating any changes.

Transpower estimates its costs of complying with the current Code obligations are approximately $21,000 per annum. This equates to a present value of approximately $179,000. In contrast, Transpower estimates its annual costs of complying with the proposed Code amendment would be approximately $7,700, with a one-off transition cost of approximately $11,000. This equates to a present value of approximately $77,000.

The Authority estimates that its costs come to approximately $7,500 per annum under the current arrangements, which equates to a present value of approximately $64,000 (assuming a 15-year discount period and a real discount rate of 8%). The Authority expects to save all of this cost under the proposal.

The second key benefit of the proposed amendment would be to make it easier for grid users and interested parties to access and review grid information. Currently, these parties contact Transpower for up-to-date grid information, rather than relying on the grid configuration document incorporated by reference into the Code. Under the proposal, these parties will be able to view grid configuration information on Transpower’s website, knowing that Transpower updates it monthly.

These savings in Transpower’s and the Authority’s market regulation costs and participants’ transaction (search) costs represent a productive economic efficiency benefit.

**Net benefit**

Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
| Evaluation of alternative means of achieving the objectives of the proposed amendment | The Authority has not identified an alternative means of achieving the objectives of the proposed amendment. |
## 2016-10 Simplifying references to time

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 10 Simplifying references to time</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem definition</strong></td>
<td>The Code contains several similar terms relating to time. The Authority has identified the following terms that can be simplified or removed:</td>
</tr>
<tr>
<td></td>
<td>• day</td>
</tr>
<tr>
<td></td>
<td>• business day</td>
</tr>
<tr>
<td></td>
<td>• working day</td>
</tr>
<tr>
<td></td>
<td>• calendar day</td>
</tr>
<tr>
<td></td>
<td>• month</td>
</tr>
<tr>
<td></td>
<td>• calendar month</td>
</tr>
<tr>
<td></td>
<td>• year</td>
</tr>
<tr>
<td></td>
<td>• calendar year</td>
</tr>
<tr>
<td></td>
<td>• financial year</td>
</tr>
<tr>
<td></td>
<td>• preceding year</td>
</tr>
<tr>
<td></td>
<td>• preceding year day</td>
</tr>
<tr>
<td></td>
<td>• qualifying date.</td>
</tr>
<tr>
<td></td>
<td>Some of these terms appear only in limited locations in the Code. Others have very similar meanings.</td>
</tr>
<tr>
<td></td>
<td>The Authority considers that simplifying the Code, by reducing the number of these terms, would promote the Authority's statutory objective. Specifically, the Authority believes it would promote the efficient operation of the electricity industry.</td>
</tr>
</tbody>
</table>

### Business day, working day

The defined term ‘working day’, which appears in 12 clauses in the Code, is very similar to ‘business day’. The difference is that ‘working day’ excludes any days in the period commencing 25 December in any year and ending on 15 January in the following year. The Authority considers that having two defined terms with similar but different meanings can be confusing, particularly for new participants. The Authority considers that, except in two locations, the term ‘working day’ can be replaced with ‘business day’ with negligible costs being imposed on industry participants.

### Calendar day

‘Calendar day’ is an undefined term that appears six times in the Code. There is no meaningful difference between ‘calendar day’ as it is used in the Code currently and the ordinary meaning of the word
‘day’. Replacing ‘calendar day’ with ‘day’ in each location would improve the readability of the Code.

**Month, Calendar month**

The undefined term ‘calendar month’ appears in 30 clauses (and three definitions) in the Code. The Authority considers that the term ‘calendar month’ is used in a way that is substantially similar to the meaning of the word ‘month’, and in some cases adding the word ‘calendar’ makes it less clear what period of time is referred to.

The readability of the Code would improve if ‘month’ replaced ‘calendar month’ where making that change would not change the meaning of the particular clause.

**Year**

‘Year’ appears in the Code in both a defined manner and an undefined manner. This is confusing and makes the Code more difficult to interpret and comply with. It also means there is a risk that future Code amendment may inadvertently use ‘year’ in the defined sense when that was not intended.

**Calendar year**

‘Calendar year’ is an undefined term that appears in 5 clauses of the Code. In four of the five places where it is used, the word ‘calendar’ is unnecessary, for example in clause 13.236A which requires disclosing participants to prepare a spot price risk disclosure statement for:

‘each quarter beginning 1 January, 1 April, 1 July, and 1 October in each calendar year’

The Code uses ‘calendar year’ to distinguish it from the other defined terms like ‘year’ and ‘financial year’. Because the other defined terms will also be replaced, changing ‘calendar year’ to ‘year’ (except in the one clause where a ‘calendar year’ from January to December is meant) will further simplify the Code and make it easier to understand.

**Financial year**

The defined term ‘financial year’ appears in only three clauses in the Code. Removing the definition and inserting its meaning in each of these three clauses would improve the readability of the Code.

**Preceding year, Preceding year day, Qualifying date**

Similarly, the defined terms ‘preceding year’, ‘preceding year day’ and ‘qualifying date’ are each used in only two clauses of the Code. Removing the definitions and inserting the meaning of these terms in the relevant clauses would improve the readability of the Code. The Authority also considers that the current definition of the term ‘qualifying date’ is confusing for participants and requires amending.
Proposal | Key elements of the proposed Code amendment are:
--- | ---
 | • to remove the definition of ‘working day’ and instead use ‘business day’ wherever ‘working day’ is currently used in the Code, and to make the following consequential amendments:
 | (a) in clause 3.14, to insert ‘(except within 20 business days of the end of the month of December)’ after ‘month’; and
 | (b) in clause 7.2E, to insert ‘(except by the 20th business day in January)’ after ‘month’.
 | • to replace all references in the Code to ‘calendar day’ with ‘day’
 | • to replace all references in the Code to ‘calendar month’ with ‘month’ where doing so would not change the meaning of the particular clause
 | • to remove the definition of ‘year’ and insert the meaning of the definition in the relevant clauses of the Code, with the exception of clause 9.21
 | • to replace references in the Code to ‘calendar year’ with ‘year’, with the exception of the two references in clause 10(6) of Schedule 14A.1
 | • to remove the definition of ‘financial year’ and insert the meaning of the definition in the relevant clauses of the Code
 | • to remove the definition of ‘preceding year’ and insert the meaning of the definition in the relevant clauses of the Code
 | • to remove the definition of ‘preceding year day’ and insert the meaning of the definition in the relevant clauses of the Code
 | • to remove the definition of ‘qualifying date’ and insert the meaning of an amended definition in the relevant clauses of the Code, so that it refers to the last day of a public conservation period, rather than the day after the last day
 | • to replace ‘previous year’ in clause 9.21 with ‘12 months immediately preceding the public conservation period’.

The Authority proposes to amend the definition of ‘qualifying date’ so that it refers to the last day of a public conservation period, rather than the day after the last day. The Authority considers this to be less confusing for participants when reading and complying with the Code.

The Authority proposes that the defined meaning of ‘year’ not be used in clause 9.21. This will rectify an unintended consequence of the current drafting. Using the defined meaning of ‘year’ means a qualifying customer’s annual consumption could be for a period almost 1–2 years before the public conservation period (if the public conservation period were to commence in late March). The Authority
The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry.

Simplifying the Code makes it easier for participants to understand and give effect to their obligations. This promotes the efficient operation of the electricity industry.

Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment is not expected to affect competition in, or the reliable supply by, the electricity industry.

The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.

The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32 of the Act.

The proposed amendment is consistent with principle 2 since it is expected to result in participants operating more efficiently and incurring lower costs complying with the Code.

It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Please refer to the qualitative cost-benefit analysis under the Regulatory Statement below.
### Statement

| **Objectives of the proposed amendment** | The objective of the proposal is to simplify the Code. This will make it easier for participants to understand the Code and comply with it. |
| **Evaluation of the costs and benefits of the proposed amendment** | The Authority considers that the expected net benefit of the proposal is positive, for the reasons set out below.  

**Costs**  
The Authority considers the only aspect of the proposal that might place some additional costs on industry participants is the proposed use of “business day” instead of “working day”. However, the Authority expects this aspect of the proposed amendment would place negligible additional costs on industry participants because:  
- using ‘business day’ instead of ‘working day’ would not place a material new obligation on participants in respect of the following clauses  
  - clause 2.8 – the Authority is not aware of a participant ever being obliged to take action under this clause. The Authority therefore considers the odds of this happening over the Christmas / New Year period to be very low  
  - clause 7.12 – the Authority is not required to publicise the system operator’s self-review report over the Christmas / New Year period  
  - clause 9.5 – moving from working days to business days would not impose a material additional obligation on the system operator, given the permitted timeframe (six months) for the system operator to consult with interested parties on a system operator rolling outage plan, consider submissions and make a decision  
  - clause 9.10 – the system operator may allow additional time for a participant to submit a revised participant rolling outage plan if this was required over the Christmas / New Year period. However, if time were of the essence, then 15 business days would be more appropriate than 15 working days  
  - clause 9.13 – it is unlikely that a participant would amend a participant rolling outage plan just before the Christmas / New Year period. Again, if time were of the essence, then 20 business days would be more appropriate than 20 working days  
  - clause 13.236A – a participant would have an extra five business days to submit a spot price risk disclosure statement at the end of December (under the proposal a participant would be able to submit the statement immediately prior to Christmas, instead of needing to do so a week prior to Christmas)  
  - clause 13.236D – the time available for a participant to |
prepare a spot price risk disclosure statement for the quarter beginning 1 January would remain unchanged under the proposal

- clause 13.236E – the timeframe for a participant to sign a spot price risk disclosure statement for the quarter beginning 1 January would remain unchanged (under the proposal a participant would be able to submit the signed statement immediately prior to Christmas, instead of needing to do so a week prior to Christmas)

- clause 13.236G – the Authority expects that it would not be notifying a disclosing participant just before Christmas of the need to submit a new spot price risk disclosure statement

- clause 13.236H – the Authority expects that it would not be notifying a disclosing participant just before Christmas of the need for an audit

- adding the words ‘within 20 business days after the end of December’ in clause 3.14 and ‘by the 20th business day of January’ in clause 7.2E would not place any material new obligation on market operation service providers.

**Benefits**

The proposal's main benefit is making it easier for participants to understand and comply with their Code obligations. This will reduce participants' costs of transacting in the electricity market and deliver a productive economic efficiency benefit. The Authority believes this benefit could be reasonably material. The following examples illustrate where some of the expected transaction cost savings from the proposal would be delivered.

Although ‘business day’ and ‘working day’ appear similar, the obligations they place on participants in December and January each year vary significantly. The proposal would remove the risk that participants face of inadvertently applying the wrong definition and consequently breaching the Code.

The definition of ‘qualifying date’ is not as intuitive or clear as it could be. The Authority believes participants would require significantly less time to correctly interpret the proposed definition than they would to interpret the current definition.

The definition of “financial year” says the Authority is to determine the date on which the financial year begins. The Authority therefore faces the cost of making a determination, including the cost of Board and management time, and publishing the determination annually for participants' information.

Lastly, and perhaps most significantly, improving the readability of the Code would save time for persons who refer to it. The saving each time a person reads the relevant Code provision subject to this proposal may be small, but the overall saving could be reasonably material across all users each year.
<table>
<thead>
<tr>
<th><strong>Net benefit</strong></th>
<th>The Authority is satisfied that the expected benefits of the proposed amendment outweigh the costs. This is on the basis that the proposal is expected to impose negligible additional costs on participants.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Evaluation of alternative means of achieving the objectives of the proposed amendment</strong></td>
<td>The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.</td>
</tr>
</tbody>
</table>
## 2016–11 Rationalising references to ‘registry’ and ‘registry manager’

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 11 Rationalising references to ‘registry’ and ‘registry manager’</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem definition</td>
<td>The Code defines both the ‘registry’ and the ‘registry manager’ as ‘the person or persons for the time being appointed as the registry manager under this Code’. However, the ‘registry’ and the ‘registry manager’ are different concepts. The ‘registry’ is the national database maintained by the Authority that contains information about each ICP. The ‘registry manager’ is a market operation service provider appointed under the Code by the Authority. Currently, where the Code uses ‘registry’ to refer to the place where information is stored, this is correct. However, in other provisions where the term ‘registry’ is used, it is clear that the correct reference should be to the ‘registry manager’ rather than the ‘registry’. For example, in clauses 11.18A and 11.20, the ‘registry’ is required to take some action. In these provisions, the registry manager should be responsible for carrying out the obligation.</td>
</tr>
<tr>
<td>Proposal</td>
<td>The Authority proposes to:</td>
</tr>
<tr>
<td></td>
<td>(a) define ‘registry’ to mean the national database maintained by the Authority that contains information about each ICP;</td>
</tr>
<tr>
<td></td>
<td>(b) define ‘registry manager’ by referring to the definition of registry manager in the Act. This is how other market operation service providers are defined in the Code;</td>
</tr>
<tr>
<td></td>
<td>(c) amend the Code to replace ‘registry’ with ‘registry manager’ in each place as appropriate, and to make other minor amendments, as necessary, to preserve the sense of the relevant Code provisions;</td>
</tr>
<tr>
<td></td>
<td>(d) amend the Code to make other minor drafting improvements.</td>
</tr>
<tr>
<td>Proposed Code amendment</td>
<td>Refer to the drafting schedule in Appendix C.</td>
</tr>
<tr>
<td>Grounds for not consulting</td>
<td>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no impact on current practice, and will change any participant's obligations. Rather, the proposed amendment would improve the clarity of the Code.</td>
</tr>
<tr>
<td>Assessment of proposed Code</td>
<td>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definitions in the manner proposed would reduce</td>
</tr>
<tr>
<td>Amendment against section 32(1) of the Act</td>
<td>confusion in this area, leading to improved operational efficiency and reduced compliance costs. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment would not affect competition or reliability.</td>
</tr>
<tr>
<td>Assessment against Code amendment principles</td>
<td>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</td>
</tr>
<tr>
<td>Principle 1: Lawfulness.</td>
<td>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.</td>
</tr>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not practicable to quantify the benefits of this amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
### Problem definition

The Code contains a large number of similar and related terms about:

- the physical connection of an asset or electrical installation to a network (including modelling of that physical connection); or
- enabling electricity to flow, or preventing the flow of electricity, across the physical connection between an asset or electrical installation and a network.

The Authority has identified the following terms that can be grouped into these two categories. The terms that are defined in the Code are included in bold:

<table>
<thead>
<tr>
<th>Physical connection</th>
<th>Enabling electricity to flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>commissioning</td>
<td>de-energise / de-energised</td>
</tr>
<tr>
<td>connect / connected / connection / connecting</td>
<td>electrically unsafe</td>
</tr>
<tr>
<td>decommission / decommissioned / decommissioning</td>
<td>energise / energised / energisation</td>
</tr>
<tr>
<td>disconnected</td>
<td>temporary energisation</td>
</tr>
<tr>
<td>directly connected</td>
<td>livened / livening</td>
</tr>
<tr>
<td>disestablished</td>
<td></td>
</tr>
<tr>
<td>electrical connections</td>
<td></td>
</tr>
<tr>
<td>electrically connecting / electrically connect /</td>
<td></td>
</tr>
<tr>
<td>electrically connected</td>
<td></td>
</tr>
<tr>
<td>electrically isolated</td>
<td></td>
</tr>
<tr>
<td>interconnect</td>
<td></td>
</tr>
<tr>
<td>permanently disconnect / permanently disconnected</td>
<td></td>
</tr>
<tr>
<td>re-connect / reconnecting / reconnection</td>
<td></td>
</tr>
<tr>
<td>temporarily disconnect / temporarily disconnected</td>
<td></td>
</tr>
<tr>
<td>temporary disconnection</td>
<td></td>
</tr>
</tbody>
</table>

Some terms are defined in the Code, or in relation to particular matters that the Code regulates, when it is not clear that a specific definition is required.

For example, the term 'connect' is defined only in relation to distributed generation, but 'connect' is used throughout the Code in a context that conveys the ordinary meaning of connect.
Another example is the definition of ‘electrically connected’, which is defined only in relation to activities regulated under Parts 11 and 15 of the Code, but again it appears that the ordinary meaning of ‘connect’ would convey what is meant. Further examples include the meaning of ‘interconnect’ in Part 6 (equivalent to the meaning of ‘connect’ used in other parts of the Code) and the meaning of ‘disestablished’ in Part 6 (equivalent to the meaning of ‘decommissioned’ in Part 10).

Some terms appear frequently in the Code even though the defined meaning does not apply. For example, ‘disconnected’ is defined to mean ‘in relation to a grid injection point, grid exit point or point of connection, that there is no load or generation at, or connected to, the grid injection point, grid exit point or point of connection in the modelling system’. Disconnected is mainly used in a context in which it means to take an action to stop the flow of electricity across the physical connection between an asset or electrical installation and a network. That usage is close to how the term ‘de-energisation’ is defined.

‘Commissioning’ is defined in the Code to mean verifying the correct operation of metering equipment installed in a metering installation. However, ‘commissioning’ is also used in Parts 8, 12, 13, 14 and 15 in relation to verifying the correct operation of assets being connected to the national transmission grid.

In Parts 8, 12 and 14 ‘decommissioning’ is undefined, and is used to mean the permanent removal of an asset or point of connection from service. This is very similar to the defined meaning of ‘decommissioning’ in Part 10.

The defined term ‘temporary energisation’ is an underutilised definition. The term is used in only four clauses, and it is not clear that a definition of ‘temporary energisation’ is required.

Lastly, some of the terms listed above have an ordinary meaning that differs from the meaning defined in the Code. For example, ‘energisation’ would ordinarily be understood as meaning to make an asset or electrical installation ‘live’. However, under the defined meaning of ‘energisation’ an asset or electrical installation may or may not be ‘live’. This could be a source of confusion for participants.

The Authority considers that simplifying the Code, by reducing the number of these terms, would promote the Authority’s statutory objective. Specifically, the Authority believes it would promote reliable supply by, and the efficient operation of, the electricity industry.

It would also reduce the risk of participants misunderstanding similar and related terms in the Code, the Act, the Electricity Act 1992 and the Electricity (Safety) Regulations 2010. A misunderstanding might

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5 “Live” is defined in the Electricity (Safety) Regulations to mean charged with electricity so that a difference in voltage exists to earth or between conductors.
have safety implications.

<table>
<thead>
<tr>
<th>Proposal</th>
<th>Key elements of the proposed Code amendment are:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• to revoke the definitions of ‘connection’ and ‘disconnection’ so these words, when used in the Code, have their ordinary meanings, consistent with the approach in the Act, the Electricity Act 1992, and the Electricity (Safety) Regulations 2010</td>
</tr>
<tr>
<td></td>
<td>• to revoke the definitions of ‘electrically connecting’, ‘de-energisation’, ‘energisation’, and ‘temporary energisation’</td>
</tr>
<tr>
<td></td>
<td>• to amend the definitions of ‘commissioning’ and ‘decommissioning’, to include the commissioning and decommissioning of an ‘asset’ and a ‘point of connection’, as these terms are defined in the Code</td>
</tr>
<tr>
<td></td>
<td>• to insert new definitions as follows:</td>
</tr>
<tr>
<td></td>
<td>- a new definition of ‘electrically connect’ which will effectively replace the current definition of ‘energisation’</td>
</tr>
<tr>
<td></td>
<td>- a new definition of ‘electrically disconnect’, which will effectively replace the current definition of ‘de-energisation’</td>
</tr>
<tr>
<td></td>
<td>• to replace, as appropriate, references to ‘connected’ and ‘energised’ in the Code with ‘electrically connected’</td>
</tr>
<tr>
<td></td>
<td>• to replace, as appropriate, references to ‘disconnected’ and ‘de-energised’ in the Code with ‘electrically disconnected’</td>
</tr>
<tr>
<td></td>
<td>• to replace references to ‘disestablished’, ‘electrically isolated’, and ‘interconnect’ in the Code with, respectively, ‘decommissioned’, ‘electrical conductors’, ‘electrical separation’ and ‘connect’</td>
</tr>
<tr>
<td></td>
<td>• to clarify that ‘electrically unsafe’ has the meaning given to it in the Electricity (Safety) Regulations.</td>
</tr>
</tbody>
</table>

The proposed Code amendment also makes a number of minor clarifications to the Code, which are linked to the key amendments listed above.

<table>
<thead>
<tr>
<th>Proposed Code amendment</th>
<th>Refer to the drafting schedule in Appendix C.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Assessment of proposed Code amendment against the Authority's objective</th>
<th>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Simplifying the Code, and aligning its terminology more closely with the terminology in other electricity industry regulation, makes it easier for participants to understand their obligations. This promotes the</td>
</tr>
</tbody>
</table>
The proposed Code amendment is not expected to affect competition in the electricity industry, and to have no material effect on the reliable supply of electricity. It is possible that the proposed amendment could promote the reliable supply of electricity. It would do so by simplifying terminology in the Code relating to connecting and disconnecting assets and ICPs, which in turn may reduce the possibility of electricity inadvertently not being supplied from/to assets and ICPs.

### Assessment against Code amendment principles

<table>
<thead>
<tr>
<th>Principle 1: Lawfulness.</th>
<th>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</td>
<td>The proposed amendment is consistent with principle 2 since it is expected to result in participants operating more efficiently and incurring lower costs complying with the Code.</td>
</tr>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken. Please refer to the qualitative cost-benefit analysis under the Regulatory Statement below.</td>
</tr>
</tbody>
</table>

### Regulatory Statement

<table>
<thead>
<tr>
<th>Objectives of the proposed amendment</th>
<th>The objective of the proposal is to simplify the Code. This will make it easier for participants to understand the Code and comply with it.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Evaluation of the costs and benefits of</td>
<td>The Authority considers the proposal would have a positive net benefit, for the reasons set out below.</td>
</tr>
<tr>
<td>the proposed amendment</td>
<td>Costs</td>
</tr>
<tr>
<td>------------------------</td>
<td>-------</td>
</tr>
<tr>
<td></td>
<td>The Authority believes the proposed amendment might place some one-off costs on industry participants. These costs would relate to updating internal procedures. The Authority expects these costs would be minor.</td>
</tr>
</tbody>
</table>

**Benefits**

The main benefit of the proposed amendment is making it easier for participants to understand and comply with their Code obligations. This will reduce participants’ ongoing costs of transacting in the electricity market and deliver a productive economic efficiency benefit. The Authority expects this benefit to be material.

In particular, the Authority believes there would be a significant benefit from making the definitions relating to the physical and electrical connection of assets and electrical installations more intuitive and understandable. The proposed amendment would also reduce the instances where the Code uses a defined term, but the defined meaning does not apply.

The Authority expects this would reduce the time spent by staff in industry participant organisations (in particular, the staff of distributors, retailers and metering equipment providers) having to clarify what the Code means. The Authority would also benefit from spending less time liaising with participants about the correct interpretation of these definitions.

Another expected benefit is the reduced possibility of electricity inadvertently not being supplied from/to assets and ICPs. This benefit also would stem from simplifying the Code terminology relating to connecting and disconnecting assets and ICPs.

As noted earlier, the proposed amendment would also reduce the risk to persons’ safety from participants misunderstanding similar and related terms in the Code, the Act, the Electricity Act 1992 and the Electricity (Safety) Regulations 2010. The Authority considers this is an important benefit of the proposed amendment.

**Net benefit**

Based on the above analysis, the Authority is satisfied that the expected benefits of the proposed amendment outweigh the expected costs.

| Evaluation of alternative means of achieving the objectives of the proposed amendment | The Authority has not identified an alternative means of achieving the objectives of the proposed amendment. |
### 2016-13 Amending the definition of ‘Information system’

<table>
<thead>
<tr>
<th>Reference No.</th>
<th>2016 – 13 Amending the definition of 'Information system'</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem definition</strong></td>
<td><strong>Background</strong></td>
</tr>
<tr>
<td></td>
<td>Various clauses in the Code require participants to convey information using the 'information system'. The information system is defined in the Code as the 'system or systems required for the conveyance of information between persons in accordance with this Code as may be approved from time to time by the Authority'.</td>
</tr>
<tr>
<td></td>
<td>The Authority has approved a number of systems for conveying information for the purposes of the definition. The systems are listed in a document entitled 'Information System Definition', which is available on the Authority's website.</td>
</tr>
<tr>
<td></td>
<td>The Information System Definition document:</td>
</tr>
<tr>
<td></td>
<td>- lists the systems that comprise the 'information system' defined in the Code</td>
</tr>
<tr>
<td></td>
<td>- lists some of the backup procedures that participants must follow if the information system is unavailable</td>
</tr>
<tr>
<td></td>
<td>- describes how information is to be published (as defined in the Code), where the Code provides that the Authority must prescribe the manner of publication for the purpose of the definition of 'information system' or for the purpose of the definition of 'publish'.</td>
</tr>
</tbody>
</table>

#### Issues

The Authority considers it is difficult for participants to determine how to transmit and publish information under the Code because:

- the document that sets out the systems approved to transmit or publish information is difficult to understand
- the definition of ‘publish’ is more complex than it needs to be.

The process of approving systems that comprise the information system is also more administratively burdensome than necessary. The number of clauses in the Code that refer to ‘information system’ or ‘publish’ means that the Information System Definition document is lengthy and administratively burdensome to keep up to date.

Changes to the Information System Definition document (for example, as a result of a Code amendment, a system change, or the creation of a new system) require consultation with participants and approval by the Authority Board. This means the process of keeping the Information System Definition document up to date is not as flexible as it could be.

Further, after the Authority has approved a system, that is the only...
system that can be used unless the document is amended. This makes it harder to introduce new technologies to convey information.

The document is more than 50 pages long, and is not easy to understand.

Participants tell the Authority they rely on instructions from service providers to find out what systems to use for particular purposes, rather than relying on the Information System Definition document. If that is correct, participants risk inadvertently breaching the Code.

The systems approved by the Authority are in many cases specified as SMTP (email), ‘as agreed by the parties’, or by publishing information on a website. The Authority considers that those types of systems should not require specific approval from the Authority.

In Part 13 of the Code, which deals with trading arrangements, the system that the Authority has approved for use is most often, but not exclusively, the Wholesale Information Trading System (WITS).

The Authority considers that each clause with the term 'information system' should be amended in one of the following ways:

- to refer to the way that information must be conveyed (in many cases, this will be WITS)
- to state that information must be conveyed using a 'system approved by the Authority'.

The systems to be approved by the Authority will most likely relate to Part 13. The Authority expects that it would publish a separate list of these approved systems in an ‘Approved Systems Document’. The Approved Systems Document would be much shorter and more user-friendly than the current Information System Definition document, and would not require updating as often.

In practice, very few changes have been required to the systems approved to convey information in Part 13. This means that the proposal should reduce the need for changes in the future.

Instead, the Authority intends to simplify the way that it prescribes and records the systems that participants must use to convey information.

**Proposal**

The Authority proposes to amend the Code to:

- revoke the definition of ‘information system’
- amend each clause that currently contains the term ‘information system’ to either:
  - refer to the way that information must be conveyed (in many cases, this will be WITS)
  - state that information must be conveyed using a 'system approved by the Authority'
- define WITS to mean the system operated by the WITS manager.
• remove references to outdated technologies, such as ‘facsimile’.

This would not change the systems that participants must use to convey information, but it would simplify the way in which the Authority prescribes and records those systems.

Related changes to the definition of ‘publish’ will further reduce the size and complexity of the Approved System Document. The details of those changes are in the proposal numbered 2016–02.

<table>
<thead>
<tr>
<th>Proposed Code amendment</th>
<th>Refer to the drafting schedule in Appendix C. Because this proposal and the proposal to change the definition of ‘publish’ are closely related, the schedule shows the drafting changes that would result if both proposals were to go ahead.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assessment of proposed Code amendment against the Authority’s objective and section 32(1) of the Act</td>
<td>The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Reducing the effort associated with approving information systems under the Code would: • lower the Authority’s costs in regulating the electricity market • make it easier for participants to understand and give effect to their obligations. This promotes the efficient operation of the electricity industry. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment is not expected to affect competition in, or the reliable supply by, the electricity industry.</td>
</tr>
<tr>
<td>Assessment against Code amendment principles</td>
<td>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</td>
</tr>
<tr>
<td>Principle 1: Lawfulness.</td>
<td>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act.</td>
</tr>
</tbody>
</table>
## Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure

The proposed amendment is consistent with principle 2. This is because the proposed amendment is expected to result in the Authority and participants operating more efficiently and in participants incurring lower costs complying with the Code.

## Principle 3: Quantitative Assessment

Some of the benefits of the proposed Code amendment can be readily quantified, but it has not been practicable to quantify others. Hence, a partial quantitative assessment of the proposed amendment’s costs and benefits has been undertaken (see below).

## Regulatory Statement

### Objectives of the proposed amendment

The objective of the proposal is to simplify the Authority’s approval of systems used under the Code. In addition to lowering the Authority’s regulatory costs, the proposal is expected to make it easier for participants to understand the Code and comply with it.

### Evaluation of the costs and benefits of the proposed amendment

The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below.

**Costs**

The Authority does not expect the proposed amendment to place additional costs on industry participants. However, if it did, those costs would be negligible.

**Benefits**

The primary benefits of the proposal are:

- to reduce the Authority’s market regulation costs
- to make it easier for participants to understand and comply with their Code obligations.

Under the proposed amendment the Authority would no longer need to update the Information System Definition document to require participants to publish certain information on their website. Changes to the document require a significant amount of Authority and industry resources. Whenever the Authority changes the document, the Authority consults with participants and gains approval from the Authority Board.

The Authority estimates that its costs alone come to approximately $5,000 per annum,\(^6\) which equates to a present value of approximately $43,000 (assuming a 15-year discount period and a real discount rate of 8%).

---

\(^6\) Relating primarily to staff time and costs.
The second key benefit of the proposed amendment would be to make it easier for participants to understand and comply with their Code obligations. When reading the Code, participants would have less need to refer to another document in order to understand an obligation. They would no longer need to refer to the Information System Definition document, which may not be up to date.

These savings in the Authority’s market regulation costs and participants’ transaction costs represent a productive economic efficiency benefit. The Authority believes this benefit would be material.

*Net benefit*

Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.

<table>
<thead>
<tr>
<th>Evaluation of alternative means of achieving the objectives of the proposed amendment</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Authority could prepare an interface control document (ICD). This document would specify the means by which market systems and participants’ systems interfaced with each other.</td>
</tr>
<tr>
<td>The ICD could consolidate information currently specified in the Information System Definition document, the WITS and Order Submission User Backup Procedures, and the functional specifications for market operation service providers’ systems.</td>
</tr>
<tr>
<td>The Authority believes that the proposal would achieve the objective of the proposed Code amendment at a lower cost than creating and maintaining an ICD.</td>
</tr>
</tbody>
</table>
## Problem definition

The Authority considers that the definition of 'publish' is unnecessarily complex.

The Code contains several similar and related terms about publishing information, including:

- publicise / publicised / publicises / publicising
- publicly available / publicly accessible
- publish / publication / published / publisher / publishes / publishing
- republish / republication / republished / republishes / republishing.

The Authority considers that simplifying the Code, by reducing the number of these terms, would promote the Authority’s statutory objective. Specifically, the Authority believes it would promote the efficient operation of the electricity industry.

### Definition of 'publish'

As currently defined, 'publish' means—

(a) in respect of information to be published by the Authority or a market operation service provider, to make such information available to the intended recipient through the information system; and

(b) in respect of a document to be published under Part 9,—

(i) to make the document available to the public, at no cost, on an internet site maintained by or on behalf of the system operator, at all reasonable times, and

(ii) to give notice in the Gazette of the document, of the fact that it is available on the Internet at no cost, and of the Internet site address; and

(c) in respect of all other information, to make available to the intended recipient in such manner as may be prescribed from time to time by the Authority,—

and published, publishes, publication, publisher and publishing have corresponding meanings.

Subclause (a) requires the Authority and market operation service providers to use the information system to publish information. The information system is the system(s) approved by the Authority for the conveyance of information between persons in accordance with the Code. However, the Authority is proposing to revoke that the
definition of ‘information system’ (see proposal 2016-01). This will require a consequential change to the definition of ‘publish’.

**Requirement to gazette changes**

Subclause (b)(i) of the definition of ‘publish’ currently applies to the following documents published by the system operator under Part 9:

- system operator rolling outage plan (SOROP)
- a supply shortage declaration
- a decision under clause 9.5(4)
- a direction under clause 9.15
- a revocation of a supply shortage declaration.

The subclause requires the system operator to publish the information on its website.

Subclause (b)(ii) requires the system operator to give notice in the *Gazette* when it publishes the information referred to in subclause (b)(i).

The requirement to publish information in the *Gazette* originated with the former Electricity Governance (Security of Supply) Regulations 2008 when the Code came into effect. It could not be removed when the system operator took over the Electricity Commission’s security of supply operational responsibilities in 2010. This was because doing so would have been inconsistent with the Act’s provisions for creating the initial version of the Code. Under section 34 of the Act, the initial Part 9 of the Code could only include changes to the Security of Supply Regulations necessary or reasonably required to ensure the Code was:

- consistent with the Act, the regulations, and any amendments made to other enactments by the Act; and
- accurate and coherent; and
- addressed any transitional issues.

The Authority considers that publication in the *Gazette* is of little or no value to participants, and imposes unnecessary costs on the system operator. The relevant *Gazette* notices simply advise participants that the system operator has published the information on its website. Unless participants subscribe to a print copy of the *Gazette*, they would need to go to the www.gazette.govt.nz website. It would be more efficient for participants to instead go directly to the www.systemoperator.co.nz website.

**Authority to prescribe how information is published**

Subclause (c) of the definition of ‘publish’ requires the Authority to prescribe how participants must make information available that is not covered by the two preceding subclauses.
What the Authority has ‘prescribed’ is listed in the Information System Definition document. The prescribed means by which information provided under subclause (c) is to be made available relates only to Parts 12 and 13 of the Code. For Part 12, the Authority has prescribed that the participant must publish the relevant information on its website. For Part 13, the Authority has prescribed that the participant must publish the information using either email or facsimile. The Authority considers that it is an unnecessary cost for the Authority to approve that information should be published on a website, or published using either email or facsimile. A lower cost approach would be for the relevant clauses in the Code to specify the form of publication.

Definition of ‘publicise’

‘Publicise’ means to make available to the public, at no cost, on the Authority’s website at all reasonable times and in any other manner the Authority may decide. This is similar to, but not exactly the same as, the definition of the word ‘publicise’ in the Act.

Section 34 of the Interpretation Act 1999 provides that a term or expression used in an instrument made under an enactment has the same meaning as it has in the enactment under which it is made. It is unhelpful and potentially confusing to use a word in the Code that is also used in the Act but with a different meaning.

‘Publicise’ is generally used in the Code when referring to information that the Authority must make available, to avoid the complicated definition of ‘publish’. Simplifying the definition of ‘publish’ would avoid the need for a separate defined term.

Definition of ‘publicly available’

‘Publicly available’ is not defined in the Code but is defined in the Act, where it means to make information available at no cost on a publicly available internet site and at the head office of the person required to make the information available, and to make copies available for purchase at a reasonable cost.

As noted above, section 34 of the Interpretation Act provides that a term or expression used in an instrument made under an enactment has the same meaning as it has in the enactment under which it is made. ‘Publicly available’ in the Code, therefore, has the same meaning as in the Act.

For the purposes of the Code, it is generally not necessary that information be made available at a head office, or for copies to be available for purchase. The intent of using the term ‘publicly available’ has been that information be published on a website.

There is one exception to this general approach. Clause 6.3(2) of the Code requires a distributor to make certain information ‘publicly available, free of charge, from its offices and Internet site’. This obligation was carried over to the Code in 2010 from the Electricity
Governance (Connection of Distributed Generation) Regulations 2007. The Authority proposes that the obligation under clause 6.3(2) of the Code for a distributor to make the information available at its offices should remain. This maintains the policy inherent in the regulations.

**Definition of 'publicly accessible'**

‘Publicly accessible’ is not defined in the Code. However, there are a number of clauses in Part 13 that require some participants to place information on a publicly accessible website.

As the new definition of ‘publish’ will require information to be placed on a participant’s website or another website specified in the Code, the Authority considers that references to ‘publicly accessible’ can be replaced with ‘publish’.

**Definition of ‘republish’**

‘Republish’ means ‘to publish again following a recalculation using revised data’ and ‘republished’ and ‘republication’ have corresponding meanings. The Code contains five references to the defined term ‘republish’. All five references relate to the republication of interim and final prices.

Elsewhere in the Code the words ‘recalculate and publish’ are used instead of ‘republish’ (see clauses 12.100 and 13.166A). This alternative wording more accurately describes what the pricing manager does. The pricing manager does not ‘republish’ a price if the new price was created after the original price was published. The pricing manager instead publishes a recalculated or revised price.

**Proposal**

The Authority proposes to:

- amend the definition of ‘publish’ to mean making information publicly available at no cost on a website
- remove the requirement on the system operator to give notice in the Gazette under Part 9 of the Code
- replace references to ‘publicly available’ in the Code with ‘publish’, except for clause 6.3(2)
- replace references to ‘publicly accessible’ in the Code with ‘publish’
- revoke the definition of ‘publicise’
- replace references to ‘publicise’ in the Code with ‘publish’
- if the Authority has approved publishing information by email or facsimile, replace those references to ‘publish’ with ‘give written notice’
- if the Code requires a participant to publish information on its website, delete the words ‘on its website’, as those words are
unnecessary

- revoke the definition of ‘republish’ and instead use ‘revise and publish’ or ‘recalculate and publish’ as appropriate in the relevant clauses in the Code
- make a number of consequential changes to the Code, as a result of the amendments listed above.

**Proposed Code amendment**

Refer to the drafting schedule in Appendix C. Because this proposal and the proposal to change the definition of information system are closely related, the schedule shows the drafting changes that would result if both proposals were to go ahead.

**Assessment of proposed Code amendment against the Authority’s objective and section 32(1) of the Act**

The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry.

Simplifying the Code makes it easier for participants to understand and give effect to their obligations. This promotes the efficient operation of the electricity industry.

Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

The proposed amendment is not expected to affect competition in, or the reliable supply by, the electricity industry.

**Assessment against Code amendment principles**

The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.

**Principle 1: Lawfulness.**

The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act.

**Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure.**

The proposed amendment is consistent with principle 2. This is because the proposed amendment is expected to result in participants operating more efficiently and incurring lower costs complying with the Code.

**Principle 3: Quantitative Assessment.**

Some of the benefits of the proposed Code amendment can be readily quantified, but it has not been practicable to quantify others. Hence, a partial quantitative assessment of the proposed amendment’s costs and benefits has been undertaken (see below).
<table>
<thead>
<tr>
<th>Regulatory Statement</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Objectives of the proposed amendment</strong></td>
<td>The objective of the proposal is to simplify the Code. This will make it easier for participants to understand their obligations in the Code and comply with those obligations.</td>
</tr>
</tbody>
</table>
| **Evaluation of the costs and benefits of the proposed amendment** | The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below.  
*Costs*  
The Authority does not expect the proposed amendment to place additional costs on industry participants. However, if it did, those costs would be negligible.  
*Benefits*  
The primary benefits of the proposal are:  
- to reduce the Authority’s market regulation costs  
- to make it easier for participants to understand and comply with their Code obligations.  
Under the proposed amendment the Authority would no longer need to update the Information System Definition document to require participants to publish certain information on their website. Changes to the document require a significant amount of Authority and industry resources. Whenever the Authority changes the document, the Authority consults with participants and gains approval from the Authority Board.  
The Authority estimates that its costs alone come to approximately $5,000 per annum,\(^7\) which equates to a present value of approximately $43,000 (assuming a 15-year discount period and a real discount rate of 8%).  
The second key benefit of the proposed amendment would be to make it easier for participants to understand and comply with their Code obligations. Participants would know from reading the Code that they needed to publish certain information on their website, or by giving written notice. They would no longer need to refer to the Information System Definition document, which may not be up to date. (This is because the Authority periodically updates the document, rather than updating it after each Code amendment.)  
These savings in the Authority’s market regulation costs and participants’ transaction costs represent a productive economic efficiency benefit. The Authority believes this benefit would be material. |

\(^7\) Related primarily to staff time and costs.
| Evaluation of alternative means of achieving the objectives of the proposed amendment | Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs. |
| Evaluation of alternative means of achieving the objectives of the proposed amendment | The Authority has not identified an alternative means of achieving the objectives of the proposed amendment. |
### Problem definition

In the Code, to ‘notify’ means to inform a person that information has been published:

*Notify means to notify the persons referred in the relevant clause by way of letter, email or facsimile, to a contact person and address provided by that person, that the information referred to in that clause has been published.*

‘Notify’ is currently used in three different ways in the Code:

- where the relevant clause also requires the notifying participant to publish information
- where the requirement to ‘notify’ implies the requirement to publish (that is, there is no separate requirement to publish)
- where there is no intention to impose an obligation to publish.

The Authority considers that it should be clear from the Code when parties are required to notify in writing and when they are required to publish information. These obligations should be express and not just implied.

The Authority also considers that it is unhelpful to give ordinary words like ‘notify’ a defined meaning. This can lead to a word acquiring a sense that was not intended.

This would promote the efficient operation of the electricity industry by making it easier for participants to understand their Code obligations.

### Removing restrictions on the form of written notification

The defined term ‘notify’ requires written notification by letter, email or facsimile. The definition unnecessarily restricts the means by which parties provide written notice to each other. Letters and facsimiles are now the exception rather than the norm.

Making the means by which participants give written notice to each other less prescriptive would allow them to use other electronic methods and to adopt new technologies.

This would not require all participants to adopt all technologies in order to be sure they could receive all notices sent. Just as participants are not required to change the way they notify information, participants would not also not compelled to adopt a new technology in order to receive notifications.

The Authority believes that simplifying the Code would promote the efficient operation of the electricity industry because participants...
could more easily understand their obligations.

<table>
<thead>
<tr>
<th>Proposal</th>
<th>The Authority proposes to amend the Code in the following way, unless the context means that the change would not be appropriate:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• remove the definition of ‘notify’</td>
</tr>
<tr>
<td></td>
<td>• replace ‘notify’ with ‘give written notice’, and specify the form of notice where necessary</td>
</tr>
<tr>
<td></td>
<td>• amend the Code to expressly provide for information to be published where publishing is currently required by the use of the term ‘notify’</td>
</tr>
<tr>
<td></td>
<td>unless the context means that the change would not be appropriate</td>
</tr>
</tbody>
</table>

| Proposed Code amendment | Refer to the drafting schedule in Appendix C. |

| Grounds for not consulting | The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no impact on current practice, and will not change any participant's obligations. Rather, the proposed amendment would improve the clarity of the Code. |

| Assessment of proposed Code amendment against the Authority’s objective and section 32(1) of the Act | The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Simplifying the Code, and making the Code more neutral to the use of technologies, makes it easier for participants to understand and give effect to their obligations. This promotes the efficient operation of the electricity industry. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment is not expected to affect competition in, or the reliable supply by, the electricity industry. |

| Assessment against Code amendment principles | The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant. |

<p>| Principle 1: Lawfulness. | The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective, and the requirements set out in section 32 of the Act. |</p>
<table>
<thead>
<tr>
<th>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</th>
<th>The proposed amendment is consistent with principle 2 since it is expected to result in participants operating more efficiently and incurring lower costs complying with the Code.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principle 3: Quantitative Assessment</td>
<td>It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</td>
</tr>
</tbody>
</table>
Appendix C  Drafting schedules
CRP 2016-07  Removing market administrator functions

Part 1

annual consumption list means the list published by the market administrator in accordance with clause 13.188

assumed co-efficient of variation means the value of co-efficient of variation that is set by the market administrator Authority for the purpose of calculating the preliminary sample size

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 and any other day from time to time declared by the market administrator Authority not to be a business day by notice to each registered participant

declaration date means the date, nominated by the profile applicant, on which the market administrator Authority must, for a particular profile, notify every registered participant of the information set out in clause 13 of Schedule 15.5 for that profile

market administrator means the market operation service provider who is for the time being appointed as market administrator under this Code

profile applicant means the participant who submitted an application to the market administrator Authority to approve a new profile or a change to an existing profile, and may be a joint entity with more than 1 participant or an independent commercial entity acting on behalf of 1 or more participants

WITS manager means the person or persons appointed by the Authority to perform the market operation service provider role of wholesale information trading system manager

Part 3

3.1 Appointment of market operation service providers
(1) The Authority must appoint a person or persons to perform each of the following market operation service provider roles:
(a) the registry manager:
(b) a reconciliation manager:
(c) a pricing manager;
(d) a clearing manager;
(e) a market administrator;
(f) a FTR manager;
(g) a WITS manager;
(h) an extended reserve manager;
(i) any other role identified in regulations as a market operation service provider role and for which market operation services are provided under this Code.

2 The Authority may appoint a person or persons to perform the market operation service provider role of wholesale information trading system provider.

Part 10

10.2 Authority’s and market administrator’s discretion and powers

1 A clause in this Part that gives the Authority or market administrator a discretion or power—
   (a) confers an absolute discretion, subject to the Authority or the market administrator, as the case may be—
      (i) taking into account any specific requirements set out in the clause; and
      (ii) observing the rules of natural justice; and
   (b) to approve an application by a person to carry out an activity under this Part, may be exercised by—
      (i) granting the application; or
      (ii) declining the application; or
      (iii) granting the application with any conditions that the Authority or the market administrator, as the case may be, considers appropriate in the circumstances.

2 The Authority or the market administrator, when exercising a discretion or power under this Part, must act in a timely manner.

3 The Authority or the market administrator must give an applicant reasons for its decision if the Authority or the market administrator—
   (a) declines an application for approval to carry out an activity under this Part; or
   (b) grants an application for approval to carry out an activity under this Part with any conditions that the Authority or the market administrator, as the case may be, considers appropriate in the circumstances.

10.19 Metering equipment provider

1 The metering equipment provider for each existing category 1 metering installation, or higher category of metering installation, being used on 29 August 2013 for an activity regulated under this Code, for a point of connection—
   (a) that is an ICP and not also an NSP, is the participant, or a consumer, who is identified in the registry as being the primary metering contact at 2400 hours on 28 August 2013:
   (b) that is an NSP and not also a point of connection to the grid—
      (i) is the participant who owns the meter for the point of connection:
      (ii) if there is more than 1 meter for the point of connection, is the participant who is appointed by the meter owners for the point of connection, or failing
agreement, appointed by the **market administrator Authority**.

**10.26 Responsibility for ensuring there is metering installation for point of connection to grid**

... (4) If the **participants** cannot agree, within 60 **business days** of the **grid owner** first being advised of the proposed new **point of connection** to the **grid**, on the **participant** to be responsible for providing the **metering installation**,—

(a) any affected **participant** may advise the **market administrator Authority** —

(i) that agreement has not been reached; and

(ii) of the identity of all affected **participants**; and

(iii) of the reasons (if and to the extent known) that agreement was not reached; and

(b) the **market administrator Authority** must determine which **participant** must provide the **metering installation**; and

(c) the **market administrator Authority** must advise—

(i) the relevant **participant** of its responsibility to provide the **metering installation**; and

(ii) the **participant** intending to **connect** to the **grid** of its determination; and

(iii) the **grid owner** of its determination.

(5) When determining which **participant** is responsible for providing the **metering installation**, the **market administrator Authority** must, unless it is satisfied that there is good reason not to do so, do so on the basis that—

(a) the **grid owner** is responsible if the **market administrator Authority** anticipates that the **point of connection** is a **GXP**; and

(b) the **participant connecting assets** to the **grid** at the **point of connection** is responsible if the **market administrator Authority** anticipates that the **point of connection** is a **GIP**.

... (9) If the **grid owner** considers, acting reasonably, that a proposed new **metering installation**, or a proposed change to an existing **metering installation**, or its configuration, requires subtraction or a **loss compensation** or **error compensation** process to determine **submission information** for the purposes of Part 15, the **grid owner** must, unless an **error compensation** process is to be applied to the **metering installation** that is already within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1—

(a) provide all relevant details to the **market administrator Authority**, in the **prescribed form**, at least 20 **business days** before—

(i) the proposed date for installing the **metering installation**; or

(ii) the proposed date for changing the **metering installation** or **metering installation’s configuration**; and

(b) respond, within 3 **business days** of receipt, to any request from the **market administrator Authority** for additional details; and

(c) ensure that any reasonable changes to the **metering installation** or its configuration requested by the **market administrator Authority** are carried out.
10.29 Electrically connecting point of connection to grid
(1) Despite clause 10.28(1), a grid owner must not electrically connect a point of connection to the grid unless it has—
(a) ensured that the processes described in clause 10.26 have been carried out; and
(b) requested, in the prescribed form, not less than 20 business days before the proposed connection date, authorisation from the market administrator Authority to connect the point of connection; and
(c) obtained the authorisation referred to in paragraph (b) from the market administrator Authority.

10.44 Metering installations that are inaccurate, defective, or not fit for purpose to be tested

(4) If the metering equipment provider and the participant requesting the test under subclause (2) cannot, within 5 business days of the metering equipment provider being advised under subclause (2)(a), agree on an ATH, either participant may advise the market administrator Authority, including the reasons, if and to the extent known, why agreement was not reached.

(5) The market administrator Authority must, within 5 business days of being advised under subclause (4), advise the metering equipment provider of the ATH that it must instruct to carry out the testing and to provide a statement of situation under subclause (1)(b).

(6) The metering equipment provider must instruct the ATH referred to in subclause (5) within 5 business days of being advised by the market administrator Authority.

10.46 Statement of situation
(2) A metering equipment provider must, within 3 business days of receiving the statement of situation, provide copies of it—
(a) to the relevant affected participants for all metering installations; and
(b) to the market administrator Authority—
   (i) for all category 3 and above metering installations; and
   (ii) if requested by the market administrator Authority, for each category 1 metering installation and each category 2 metering installation.

10.49 NSP table
(1) The market administrator Authority must publish and maintain an NSP table, or ensure that an NSP table is published and maintained, on the Authority’s website.
(2) The reconciliation manager must advise the market administrator Authority of any change to the information contained in the NSP table within 1 business day of becoming aware of such change.
(3) The market administrator Authority must update the NSP table, or ensure that the NSP table is updated, within 2 business days of being advised by the reconciliation manager under subclause (2).

10.51 Transitional provisions
...
(6) The following continue in effect despite anything else in, or the coming into force of, this Part, to the extent that they relate to or concern the same, or similar, obligations under this Part, and will apply to a participant’s obligations under or compliance with, the relevant obligation under this Part:

…

(f) a variation approved by the market administrator under COP 10.5:

Schedule 10.7
32 Alternative certification requirements for metering installation incorporating measuring transformer

…

(2) The metering equipment provider must, if a metering installation for which it is responsible has been certified under subclause (1),—

(a) by no later than 10 business days after the date of certification of the metering installation, advise the market administrator in the prescribed form of—

(i) all relevant details of the metering installation; and

(ii) the reason or reasons why the ATH could not obtain physical access to the measuring transformer; and

(iii) the reason or reasons why the accuracy of the metering installation cannot be outside of the applicable accuracy requirements set out in Table 1 of Schedule 10.1; and

(iv) the metering installation certification expiry date; and

(b) respond, within 5 business days, to any requests from the market administrator for additional information; and

…

(4) If the market administrator subsequently determines that the ATH could have obtained physical access to test an installed measuring transformer in the metering installation, the metering installation is deemed to be defective and the metering equipment provider responsible for the metering installation must comply with clauses 10.43 to 10.48.

Part 11

11.27 Reports to the market administrator

By 1600 hours on the 1st business day of each calendar month, the registry must deliver to the market administrator a report summarising the number of events that have not been notified to the registry, of which it is aware, within the timeframes specified in this Part.

Schedule 11.1
1 ICP identifiers

(1) A distributor must create an ICP identifier for each ICP on each network for which the distributor is responsible in accordance with the following format:
yyyyyyyyyyxxccc

where

yyyyyyyyyy is a numerical sequence provided by the distributor

xx is a code assigned by the Authority to the issuing distributor that ensures the ICP is unique

ccc is a checksum generated according to the algorithm provided by the market administrator Authority

9 Traders to provide ICP information to registry

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

(a) the participant identifier of the trader;

(b) the profile code of each profile at that ICP approved by the market administrator Authority in accordance with clause 13 of Schedule 15.5:

25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network

(1) If an NSP is to be created or decommissioned,—

(a) the participant specified in subclause (3) in relation to the NSP must notify the reconciliation manager of the creation or decommissioning; and

(b) the reconciliation manager must notify the market administrator Authority and affected reconciliation participants of the creation or decommissioning no later than 1 business day after receiving the notification in paragraph (a).

(2) If a distributor wishes to change the record in the registry of an ICP that is not recorded as being usually connected to an NSP in the distributor's network, so that the ICP is recorded as being usually connected to an NSP in the distributor's network (a "transfer"), the distributor must notify the reconciliation manager, the market administrator Authority, and each affected reconciliation participant of the transfer.

29 Obligations concerning change in network owner

(1) If a network owner acquires all or part of an existing network, the network owner must notify the following of the acquisition:

…

(c) the market administrator Authority:

Schedule 11.2

2 The applicant distributor must notify the market administrator Authority of the transfer.

5 The applicant distributor must give the market administrator Authority confirmation that the applicant distributor has received written consent to the proposed transfer from—
(a) the distributor whose network is associated with the NSP to which the ICP is recorded as being connected immediately before the notification, except if the notification relates to the creation of an embedded network; and
(b) every trader who trades electricity at any ICP nominated at the time of notification as being supplied from the same NSP to which the notification relates.

7 The market administrator Authority must not authorise the change of any information on the registry if clauses 2 to 5 are not complied with.

7A Despite clause 7, the market administrator Authority may authorise the change if the applicant distributor has not notified the market administrator Authority within the time frame required under clause 4, if—
(a) the applicant distributor has complied with clauses 2, 3 and 5; and
(b) the market administrator Authority considers that it has not been materially disadvantaged by the applicant distributor's failure to comply with clause 4.

9 The registry must remove any information that has been notified to the registry under clause 7 of Schedule 11.1 relating to an ICP for which a transfer has been notified under this Schedule, if the information was to have come into effect after the date on which the market administrator Authority authorises the change of information on the registry under this Schedule.

10 A transfer may take effect on a date that is before the date on which it is notified only with the consent of the market administrator Authority.

Part 13

13.23 Backup procedures if information system is unavailable
(1) If the information system 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 by the market administrator WITS manager.
(2) The backup procedures referred to in subclause (1) must be specified by the market administrator WITS manager following consultation with each purchaser, generator and the system operator. The market administrator WITS manager must ensure that there is always a backup procedure notified to the Authority and each purchaser, generator and the system operator.

13.36 Backup procedures if information system is unavailable
(1) If the information system is unavailable to receive information or confirm the receipt of information, the grid owner or the system operator, as the case may be, must follow the backup procedures specified by the system operator.
(2) The backup procedures referred to in subclause (1) must be specified by the market administrator system operator following consultation with grid owners and the system operator. The market administrator system operator must ensure that there is always a backup procedure notified to the Authority and grid owners and the system operator.
13.52 Backup procedures if information system is unavailable

(1) If the information system is unavailable to receive reserve offers or cancellations of reserve offers or to confirm the receipt of such reserve offers or cancellations, an ancillary service agent or the system operator, as the case may be, must follow the backup procedures specified by the market administrator.

(2) The backup procedures referred to in subclause (1) must be specified by the market administrator following consultation with ancillary service agents and the system operator. The market administrator must ensure that there is always a backup procedure notified to the Authority, ancillary service agents and the system operator.

13.55 Availability of bids, offers, and reserve offers

(1) The market administrator must, within 24 hours of the end of each day, make available all final bids, final offers and final reserve offers received for the trading periods of the previous trading day.

(2) All information to be made available by the market administrator under this clause must be—
   (a) transmitted to participants through the electronic facilities contained in the information system; and
   (b) placed on a publicly accessible website—
       and must remain available for inspection through the electronic facilities contained in the information system and on the publicly accessible website, for a period of at least 4 weeks.

(3) If the information system is unavailable to send information under subclause (2)(a), the market administrator must follow the backup procedures specified by the market administrator from time to time.

(4) The backup procedures referred to in subclause (3) must be put in place by the market administrator in consultation with purchasers, generators and ancillary service agents. The market administrator must ensure that there is always a backup procedure notified to the Authority, purchasers, generators and ancillary service agents.

(5) If the publicly accessible website on which information is placed under subclause (2)(b) is not available the market administrator is not obliged to follow any backup procedures, but the market administrator must make the information available as soon as practicable once the publicly accessible website becomes available.

13.67 Transmission of information through information system

...
manager must ensure that there is always a backup procedure notified to the Authority, the system operator, the clearing manager, and the pricing manager.

13.91 Transmission of information through information system

(2) If the information system is unavailable to send information under clauses 13.89 to 13.96, the system operator must follow the backup procedures specified by the market administrator/WITS manager.

(3) The backup procedures referred to in subclause (2) must be specified by the market administrator/WITS manager following consultation with purchasers, generators and the system operator. The market administrator/WITS manager must ensure that there is always a backup procedure notified to the Authority, purchasers, generators and the system operator.

13.92 Transmission of information through website

(1) The information (if any) received from the system operator under clause 13.90 must be made available by the market administrator/WITS manager by placing that information on a publicly accessible website.

(2) If the publicly accessible website upon which information is placed under subclause (1) is no longer available, the market administrator/WITS manager is not required to follow any backup procedures, and the market administrator/WITS manager is not required to make the information available on the publicly accessible website at a later time.

13.93 Market administrator/Authority to appoint person to monitor and assess demand side participation and real time prices

(1) The market administrator/Authority may, or may appoint a person at any time to, monitor and assess the real time prices made available by the system operator under clauses 13.89 to 13.96 in the context of demand side participation.

(2) The system operator must use reasonable endeavours to make available to the market administrator/Authority or the person appointed by the market administrator/Authority under subclause (1), in a manner agreed between the system operator and that person,—

(a) if that person is not the market administrator/Authority, the information the system operator makes available to the participants and the market administrator/Authority under clause 13.90; and

(b) for each grid injection point and each grid exit point, a volume weighted average of the real time prices for each trading period.

13.106 Transmission of information through information system

(2) If the information system is unavailable to send information the system operator must follow the backup procedures specified by the market administrator/WITS manager.

(3) The backup procedures referred to in subclause (2) must be specified by the market administrator/WITS manager following consultation with the system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents. The market administrator/WITS manager must ensure that there is always a backup procedure notified to the Authority, the system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents.
13.114 Information to be transmitted through information system

(2) If the information system is not available to send information under this clause the clearing manager must follow the backup procedures specified by the market administrator/WITS manager.

(3) The backup procedures referred to in subclause (2) must be specified by the market administrator/WITS manager following consultation with generators and the clearing manager.

13.188 Market administrator/Reconciliation manager to publish annual consumption list

(1) At least once every 6 months, the reconciliation manager must give the market administrator/Authority an annual consumption list.

(3) The market administrator/reconciliation manager must publish the list within 1 business day of receiving—providing it to the Authority.

13.191 Backup procedures if information system is unavailable

(1) If the information system is unavailable to send information under clauses 13.135 to 13.191, each grid owner and the pricing manager must follow the backup procedures specified by the market administrator/WITS manager.

(2) The backup procedures referred to in subclause (1) must be specified by the market administrator/WITS manager following consultation with generators, purchasers, ancillary service agents, the grid owners and the pricing manager.

(3) The market administrator/WITS manager must ensure that there is always a backup procedure notified to the Authority, all generators, purchasers, ancillary service agents, grid owners and the pricing manager.

13.211 Backup procedures if information system is unavailable

(1) If the information system is unavailable to send information under clauses 13.199 and 13.208 the clearing manager must follow the backup procedures specified by the market administrator/WITS manager from time to time.

(2) The backup procedures referred to in subclause (1) must be specified by the market administrator/WITS manager following consultation with generators, ancillary service agents, purchasers and the clearing manager. The market administrator/WITS manager must ensure that there is always a backup procedure notified to the Authority, generators, ancillary service agents, purchasers and the clearing manager.

13.213 Daily reports

(1) On each trading day the pricing manager must provide the market administrator/Authority with a written report for the trading periods beginning at 0700 hours on the previous trading day and ending with the trading period beginning at 0630 hours on the trading day the report is due to be given, specifying—
13.214 Market administrator Authority to publish pricing manager reports
(1) By the 15th business day of each calendar month, the market administrator Authority must publish the sections of the reports of the pricing manager given in the previous calendar month under clause 13.213 that relate to any alleged breaches of this Code by the pricing manager.
(2) By the 15th business day of each calendar month the market administrator must refer the reports received in the previous calendar month to the Authority.

13.216 Daily situation report
On the day following publication of final prices and final reserve prices in respect of the trading day to which the published prices relate, the pricing manager must give the market administrator Authority a report containing—

…

13.229 Submitting party to check if no confirmation received
(1) If a party that submitted information to the information system has not received confirmation that its information has been received by the information system within 6 hours of submitting the information to the information system, that party must, within 1 business day of the expiry of that 6 hour period, contact the market administrator WITS manager to check whether the information has been received by the information system.

Part 14

14.68 Monthly divergence reports to be prepared by clearing manager
(1) The clearing manager must report to the market administrator Authority in writing under this clause.
(2) The clearing manager must give the report to the market administrator 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.

14.69 Market administrator Authority to publish clearing manager reports
(1) By the 15th business day of each calendar month, the market administrator Authority must publish the sections of the report, received in the previous calendar month from the clearing manager in accordance with clause 14.68, that relate to any breaches of this Code by the clearing manager.
(2) By the 15th business day of each calendar month the market administrator must also refer the report received in the previous calendar month to the Authority.

Part 15

Schedule 15.2
8 Non half hour meter reading on 12 monthly basis
(1) Each reconciliation participant must ensure that, at least once every 12 months, a validated meter reading is obtained for every meter register for non half hour metered
ICPs that the reconciliation participant trades continuously for each 12 month period. In carrying out this obligation—

(a) each reconciliation participant must report to the market administrator Authority, in relation to each NSP, the percentage of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 12 month period. This report must be submitted no later than 20 business days after the end of each month; and

(b) if the percentage reported in accordance with paragraph (a) is less than 100%, the market administrator Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve a level of performance that, in the market administrator Authority’s assessment, is reasonable.

9 Non half hour meter reading every 4 months

(1) Each reconciliation participant must ensure, in relation to each NSP, that a validated meter reading is obtained, at least once every 4 months, for 90% of the non half hour metered ICPs at which the reconciliation participant trades continuously for each 4 months for which consumption information is required to be reported into the reconciliation process. In carrying out this obligation—

(a) each reconciliation participant must report to the market administrator Authority the percentage, in relation to each NSP, of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 4 month period. This report must be submitted no later than 20 business days after the end of each month; and

(b) if the percentage reported in accordance with paragraph (a) is less than 90% in relation to any NSP, the market administrator Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve acceptable performance.

(3) The reconciliation participant must report to the market administrator Authority monthly on a rolling 4 month basis the percentage of non half hour meter interrogations within that period.

10 Allocation by profile

If submission information is submitted as non half hour quantities to be allocated to trading periods by profile shape, the reconciliation manager must use the appropriate shape for the profile code contained in the submission information, if—

(a) the profile code has been approved by the market administrator Authority in accordance with Schedule 15.5; and

12 Application of profile shapes

The reconciliation manager must calculate the trading period information by applying the profile shape for the profile code specified in the submission file provided by the reconciliation participant if—
(a) the profile code has been approved by the market administrator Authority in accordance with Schedule 15.5; and

13 Balancing area derived profiles approved in accordance with Appendix 1 of Schedule 15.5
The reconciliation manager must calculate the trading period information by applying 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 market administrator Authority for use as a balancing area derived profile in accordance with Schedule 15.5; and

... (c) if the profile code had not been approved by the market administrator Authority, or notified to the reconciliation manager, the reconciliation manager must use the final residual profile.

Schedule 15.5
2 Departure from requirements
The market administrator Authority may approve situations that depart from the requirements of this Schedule if it is satisfied that such departure would have minimal adverse effects on each participant.

11 Change of profile
(1) A profile owner may apply to the market administrator Authority to change a profile.
(2) An application must contain—
   (a) the profile code for the profile to which the proposed change relates; and
   (b) details of the proposed change.
(3) The market administrator Authority must not approve an application unless the market administrator Authority is satisfied that the requirements in clause 20 (for NSP derived profiles), and clauses 25 and 27 (for statistically sampled engineered profiles), with all necessary modifications, have been met.
(4) The market administrator Authority must advise the profile applicant if the application has been approved or rejected, or of additional steps that must be completed before the application can be considered, no later than 15 business days after receipt of the application.

13 Allocation and storage of profile codes
(1) The market administrator Authority must determine the profile code for an approved profile in accordance with this clause.

... (5) The market administrator Authority must publish the following information for all approved profiles in the following format:

19 Applications
(1) An application to introduce a new NSP derived profile must be submitted to the market administrator Authority, who must either advise the profile applicant of further actions, or must approve or reject the application no later than 15 business days after its receipt.

20 Assessment
Before approving a profile, the market administrator Authority must be satisfied that—

22 Withdrawal of applications
If an application is withdrawn by a profile applicant at any time following the declaration date, but before approval, the market administrator Authority must advise all participants.

23 Rejected applications
If an application is rejected, the market administrator Authority must provide to the profile applicant a detailed explanation of why the application was rejected, together with actions required for a reconsideration of the application.

24 Use of approved profiles
(1) A profile must not be used for reconciliation until it is approved by the market administrator Authority in accordance with clauses 19 and 20. The use of a profile must be effective from a date decided by the market administrator Authority, but not earlier than the 1st day of the month following the declaration date.

26 Applications
(1) An application to introduce a new profile must be submitted to the market administrator Authority, who must either advise the profile applicant of further actions, or approve or reject the application in writing no later than 15 business days after its receipt.

28 Sampling requirements
(2) For profiles that require statistical sampling, the market administrator Authority must specify the preliminary sample size and draw a preliminary sample of ICP identifiers from the profile population list, or must accept appropriate sampling performed by the profile applicant. Half hour research meters must be, or must have been, installed and operated by the profile applicant for this preliminary sample. The market administrator Authority must require a minimum sampling period of 60 calendar days, and not more than 12 months. The market administrator Authority may withdraw ICP identifiers from the profile population list if it can be shown by the profile applicant that those ICP identifiers are in sites that are difficult to meter.

(3) The average unit cost and standard deviation of the unit cost must be calculated using the 60 days or more of data obtained as described above. If the sample co-efficient of variation is less than or equal to the profile acceptance limit specified in Appendix 2, the size of the profile sample must be the profile sample size. The market administrator Authority must provide a standard set of synthetic price scenarios to determine the variability of unit costs.
(4) If the sample co-efficient of variation is more than the profile acceptance limit, the market administrator Authority can reject the application, or can require the profile applicant to supply additional information until the market administrator Authority is satisfied that there is no clear evidence to suggest the population co-efficient of variation exceeds the profile acceptance limit.

(5) If the preliminary sample size is less than the profile sample size, the market administrator Authority must draw an additional random sample. The size of the additional random sample must equal the shortfall.

30 Withdrawal of applications
If an application is withdrawn by a profile applicant at any time following the declaration date, but before approval, the market administrator Authority must advise all participants.

31 Rejected applications
(1) If an application is rejected, the market administrator Authority must provide the profile applicant with a detailed explanation of why the application was rejected, together with actions required for a reconsideration of the application.

... (5) The market administrator Authority must determine if additional ICP identifiers are required to make up the refined preliminary sample.

32 Use of approved profiles
(1) A profile must not be used for reconciliation until the market administrator Authority approves it. The use of a profile must be effective from a date decided by the market administrator Authority, but not earlier than the 1st day of the month following the declaration date. If an approved profile is used for reconciliation, every ICP identifier on the profile population list must be reconciled under that profile.

33 Profile maintenance and changes
... (2) The profile owner must maintain a current profile population list. The profile owner must inform the market administrator Authority when an update is necessary (refer subclause (3)). The profile population list is subject to random audit by the market administrator Authority or its appointed audit agent.

(3) The profile sample must be updated when membership of the profile population has changed by more than 20% since the sample date. The profile owner must, no later than 10 business days after the profile owner becomes aware of such change in membership, notify the market administrator Authority of the changes in the profile population list. The market administrator Authority must determine, and notify the profile owner of, any required modifications to the profile sample. The profile owner has 1 month from the date of notification by the market administrator Authority to ensure that certified half hour meters are installed in the metering installations of these ICP identifiers, and that the metering installations are fully certified.

(4) If more than 5% of the profile sample has been lost or removed, the profile owner must submit to the market administrator Authority a list of ICP identifiers in the current
profile sample who have been lost or removed from the profile population list. The market administrator Authority must draw ICP identifiers from the profile population list to replace those who are lost or removed from the profile sample. The profile owner must ensure that certified half hour meters are installed in the metering installations of these ICP identifiers, and that the metering installations are fully certified, no later than 1 month after the market administrator Authority issues its determination of the appropriate replacement ICP identifiers.

34 Exceptions to sampling methodology
The market administrator Authority may allow different sampling methodologies that are not described in this Schedule, only if—
(a) the methodology can, in the market administrator Authority’s assessment, produce sample data that meets the precision standards specified under Appendix 2; and
(b) the market administrator Authority or its audit agent is satisfied that the methodology can be audited to the same degree of rigour as the sampling methodology outlined in Appendix 2; and...

35 Audits
(1) A participant may request the selective audit of any participant’s compliance with this Schedule or the participant’s application and use of any profile.
(2) The application of all profiles must be audited by the market administrator Authority or its agent in a random order at least once every 2 years by application of a selection process maintained by the market administrator and monitored by the Authority.

36 Reviews
(1) The market administrator Authority must review the structure of every approved profile at least every 3 years.
(2) Each review must determine whether—
(a) the criteria for profile definition are still appropriate; and
(b) if applicable, the existing sample needs to be redrawn.

37 Removal of profiles
(1) The market administrator Authority must immediately remove a profile that fails an audit from the list of approved profiles held by the market administrator Authority.
...
(3) A profile may be removed at the request of the profile owner who introduced it, or for such other reasons as may be decided by the market administrator Authority.
(4) A request for the removal of a profile must be notified to the market administrator Authority, and must be effective from the following settlement period.
(5) If a profile is removed, the market administrator Authority must decide on the actions to be taken with respect to the ICP identifiers to which the removed profile applied.

Appendix 1, clause 12 Profile class 2.5, non half hour embedded generation
(1) There are 2 types of non half hour embedded generator profile as set out in subclause (2). Details of the operation and application of those profiles must be
determined by the **market administrator Authority**. The **profiles** must be submitted by the market administrator Authority to the reconciliation manager.

**Appendix 2, clause 2 Preliminary sample**

(1) Unless the **profile applicant** has better information available that is acceptable to the market administrator Authority, the size of the **preliminary sample** must be determined by the following **preliminary sample size** formula:

...  

(8) The **profile applicant** must collect **half hour** data from the **preliminary sample** over a period of at least 60 calendar days. The data, in its processed form, must be submitted to the market administrator Authority for consideration. The data processing must include calculations of **unit costs**, and of mean and standard deviation of **unit costs**, over the sample period.

**Schedule 15.5**

5 **Reviews**

(1) The statistical parameters must be monitored by the market administrator Authority and reviewed when the market administrator Authority considers it appropriate. Modifications of those parameters are expected as the industry gains experience in the use of statistical **profiles**. Industry **participants** will be consulted as part of the review process.

(2) Each year the market administrator Authority must review data gathered during the year for each **profile sample**, and must re-examine the **co-efficient of variation** and the sample size. A relative standard error of 5% and a confidence level of 99% must be applied initially. A figure of 2% for the relative standard error is expected to be adopted by the market administrator Authority following the first 12-monthly review and may thereafter be reviewed from time to time.

(3) Reviews of existing standards must take place in the 6th month and the 12th month during the 1st year of **profile** introduction.
8.54T Transitional provisions for extended reserve

(1) If the system operator takes any action before clause 8.54D comes into force that, if that clause had been in force at the time of the action, would have contributed to complying with that clause, the action is deemed to have been taken when that clause was in force.

(2) The system operator must comply with clause 8.54D, for the first time after that clause comes into force, so that it gives a draft of the extended reserve technical requirements schedule to the Authority under clause 2(2) of Schedule 8.5 no later than 40 business days after clause 8.54D comes into force.

(3) The system operator must conduct the first review of the extended reserve technical requirements schedule under clause 8.54E so that the system operator advises the Authority of its decision under clause 8.54E(1) no later than 60 months after the first extended reserve technical requirements schedule was published under clause 8.54D.

(4) No later than 40 business days after the system operator publishes the initial extended reserve technical requirements schedule under clause 8.54D, the extended reserve manager must, under clause 5(2) of Schedule 8.5, give the Authority and the system operator—
   (a) a draft of the extended reserve selection methodology; and
   (b) one or more worked examples of an extended reserve procurement schedule, created using—
      (i) the draft extended reserve selection methodology; and
      (ii) data specified by the system operator.

(5) In the case of the first selection process after clause 8.54J comes into force, the Authority must make a direction under clause 8.54J(1) no later than 5 business days after the initial extended reserve selection methodology is published.

(6) The first implementation plan that an asset owner gives the system operator under clause 8.54M(2) must specify how the asset owner will implement the transition from complying with its obligations (if any) under Schedule 8.3, Technical Code B, clause 7 as before that clause came into force, to complying with its extended reserve procurement notice.

(7) The first statement of extended reserve obligations that the system operator issues to each asset owner under clause 8.54P must specify the date on which it comes into force.

(8) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 6, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each North Island distributor that was required to comply with those clauses before the commencement of this clause must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—
   (a) 7 August 2024; or
   (b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the distributor.

(9) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 7, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each North Island distributor that was required to comply with those clauses before the commencement of this clause must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—
   (a) 7 August 2024; or
   (b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the distributor.
Participation Code Amendment (Extended Reserve) 2014, each South Island grid owner that was required to comply with those clauses before the commencement of this clause must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—
(a) 7 August 2024; or
(b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the grid owner.

(10) However, subclause (9) applies as if Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) was amended from 7 May 2015 by replacing "45.5 Hertz" with "46.5 Hertz".

(11) Clause 8.29(2) does not apply in respect of an application for a dispensation from a South Island grid owner until 7 August 2024.

8.54U Transitional provisions for change to frequency limit in South Island

(1) No later than 7 February 2015, each South Island grid owner must prepare and give the system operator a plan for complying with Schedule 8.3, Technical Code A, clause 7(6)(d)(ii), as modified by clause 8.54T(10).

(2) The system operator must approve a plan received under subclause (1) subject to any changes that the system operator considers necessary.

(3) A South Island grid owner does not breach Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) if the grid owner complies with a plan approved by the system operator under subclause (2).

Part 17

17.48A Transitional provisions for extended reserve

(1) If the system operator takes any action before clause 8.54D comes into force that, if that clause had been in force at the time of the action, would have contributed to complying with that clause, the action is deemed to have been taken when that clause was in force.

(2) The system operator must comply with clause 8.54D, for the first time after that clause comes into force, so that it gives a draft of the extended reserve technical requirements schedule to the Authority under clause 2(2) of Schedule 8.5 no later than 40 business days after clause 8.54D comes into force.

(3) The system operator must conduct the first review of the extended reserve technical requirements schedule under clause 8.54E so that the system operator advises the Authority of its decision under clause 8.54E(1) no later than 60 months after the first extended reserve technical requirements schedule was published under clause 8.54D.

(4) No later than 40 business days after the system operator publishes the initial extended reserve technical requirements schedule under clause 8.54D, the extended reserve manager must, under clause 5(2) of Schedule 8.5, give the Authority and the system operator—
   (a) a draft of the extended reserve selection methodology; and
   (b) one or more worked examples of an extended reserve procurement schedule, created using—
      (i) the draft extended reserve selection methodology; and
      (ii) data specified by the system operator.
(5) In the case of the first selection process after clause 8.54J comes into force, the Authority must make a direction under clause 8.54J(1) no later than 5 business days after the initial extended reserve selection methodology is published.

(6) The first implementation plan that an asset owner gives the system operator under clause 8.54M(2) must specify how the asset owner will implement the transition from complying with its obligations (if any) under Schedule 8.3, Technical Code B, clause 7, as before that clause came into force, to complying with its extended reserve procurement notice.

(7) The first statement of extended reserve obligations that the system operator issues to each asset owner under clause 8.54P must specify the date on which it comes into force.

(8) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 6, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each North Island distributor that was required to comply with those clauses before the commencement of this clause must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—
   (a) 7 August 2024; or
   (b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the distributor.

(9) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 7, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each South Island grid owner that was required to comply with those clauses before the commencement of this clause must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—
   (a) 7 August 2024; or
   (b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the grid owner.

(10) However, subclause (9) applies as if Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) was amended from 7 May 2015 by replacing "45.5 Hertz" with "46.5 Hertz".

(11) Clause 8.29(2) does not apply in respect of an application for a dispensation from a South Island grid owner until 7 August 2024.

17.48B Transitional provisions for change to frequency limit in South Island

(1) No later than 7 February 2015, each South Island grid owner must prepare and give the system operator a plan for complying with Schedule 8.3, Technical Code A, clause 7(6)(d)(ii), as modified by clause 17.48A(10).

(2) The system operator must approve a plan received under subclause (1) subject to any changes that the system operator considers necessary.

(3) A South Island grid owner does not breach Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) if the grid owner complies with a plan approved by the system operator under subclause (2).

...
Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be an unconditional guarantee or letter of credit provided under clause 3 of Schedule 14A.1.

(2) A security bond provided and maintained under clause 14.5(d) immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a security bond provided under clause 4 of Schedule 14A.1.

(3) If the Authority has approved a similar security under clause 14.5(f) and the approval was still in effect immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force, the security is deemed to be approved by the Authority under clause 5 of Schedule 14A.1.

(4) A hedge settlement agreement lodged under clause 14.5(e) and still in effect immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force ceases to be lodged.

17.210B Cash deposits

(1) A cash deposit account established under clause 14.7(1) immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a cash deposit account established under clause 14A.11(1).

(2) The clearing manager must, as soon as practicable after the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 comes into force, obtain the acknowledgement referred to in clause 14A.11(3).

(3) Bank fees that were owed in relation to a cash deposit under clause 14.11 immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force are deemed to be bank fees owed under clause 14A.15.

(4) Interest accrued under clause 14.10 immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is payable under that clause as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.

17.210C Change in form of security

A notice given under clause 14.13 that was in force immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a notice given under clause 14A.7.

17.210D Reductions and releases

A notice given under clause 14.14 that was in force immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a notice given under clause 14A.8.

17.210E Release of security

A notice given under clause 14.16 that was in force immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a notice given under clause 14A.9.
17.210F Level of security
A call made under clause 14.18 and not satisfied immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force must be satisfied under that clause as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.

17.210G Information, monitoring, and reporting
(1) Historical records or a business plan submitted under clause 14.23 immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force are deemed to be historical records or a business plan, as the case may be, submitted under clause 14A.16.
(2) Information provided under clause 14.24 or 14.26 before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be information provided under clause 14A.17.
(3) Information provided under clause 14.25 before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be information provided under clause 14A.18.
(4) If a person had consented to the disclosure of information under clause 14.27 before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force, the person is deemed to have consented to the disclosure of the information under clause 14A.19(a).

17.210H Disputes
A matter that was referred to the Rulings Panel under clause 14.29(1) that was not resolved immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 is to be dealt with as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.

17.210I Invoices and payments
(1) An invoice issued under clause 14.36 or a pro forma invoice issued under clause 14.44 that remained unpaid immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force remains in effect as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.
(2) Interest that was owed under clause 14.50 immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be interest owed under clause 14.64 and continues to accrue accordingly.

17.210J Operating account
(1) An operating account established under clause 14.43(1) immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be an operating account established under clause 14.66(1).
(2) The clearing manager must, as soon as practicable after the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 comes into force, obtain the acknowledgement referred to in clause 14.43(2).

17.210K FTR account
The clearing manager must, as soon as practicable after the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 comes into force, close the FTR account established under clause 14.43A and deposit the proceeds into the operating account.

17.210L Defaults
(1) An event of default under clause 14.55 that had occurred and was continuing immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be an event of default under clause 14.41.
(2) Despite subclause (1), further funds constituting late payments received by the clearing manager in respect of any billing period that occurred before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force must be dealt with as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.
(3) Despite clause 14A.22(5), if an event of default was continuing in relation to a participant immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force, the participant’s post default exit period begins—
   (a) for an event of default relating to a retailer’s use-of-system agreement with a distributor under clause 14.55(h), on the date on which the Authority gave notice to the participant under clause 2(1) of Schedule 11.5; or
   (b) for any other event of default, on the date on which the clearing manager notified the participant that it had committed an event of default under clause 14.57.

17.210M Disputed invoices
(1) A dispute notified under clause 14.64 that was not resolved immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is to be dealt with as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.
(2) A dispute that was referred to the Rulings Panel under clause 14.64(1) that was not resolved immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is to be dealt with as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.

17.210N Washups
(1) Corrected information received under clause 14.65 before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be corrected information received under clause 14.36.
(2) An invoice issued under clause 14.72 that remained unpaid immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment...
2013 came into force remains in effect as if the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 had not been made.

17.210O Reporting obligations

(1) A report made under clause 14.74 before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a report made under clause 14.68 and may be published accordingly.

(2) A request made under clause 14.76 immediately before the Electricity Industry Participation (Settlement and Prudential Security) Code Amendment 2013 came into force is deemed to be a request made under clause 14.70.
CRP 2016-09  Changing the way Transpower makes grid information available

Part 12

12.106 Interconnection asset capacity and grid configuration
(1) The interconnection asset capacity and grid configuration set out in schedule F6 of section VI of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the interconnection asset capacity and grid configuration that applies at the commencement of this Code.
(2) Clause 12.110 applies to the interconnection asset capacity and grid configuration.

12.107 Transpower to publish interconnection asset capacity and grid configuration identify interconnection branches, and propose service measures and levels
(1) Transpower must publish provide the Authority with the information set out in subclause (4) and a diagram showing the configuration of the grid, other than connection assets.
(1A) Transpower must publish a monthly update of the information and diagram described in subclause (1), showing any changes since the end of the previous month.
(2) The interconnection asset capacity and grid configuration referred to in subclause (1) must be provided in the form required by the Authority that Transpower considers suitable, taking into account the requirements of its customers and other relevant stakeholders.
(3) The interconnection asset capacity and grid configuration referred to in subclause (1) must be provided within 3 months of the date on which the Authority, in accordance with subclause (2), sets the form in which the interconnection asset capacity and grid configuration must be provided.
(4) The information required under subclause (1) is—
   (a) for each interconnection circuit branch, the following service measures and service levels:
      (i) the overall continuous capacity rating of the interconnection circuit branch, for both summer and winter periods in MVA and amperes;
      (ii) the level of impedance of the interconnection circuit branch both resistive and reactive and for assets arranged in both shunt and series in PU, using a base of 100 MVA, provided the impedance of the interconnection circuit branch is equal to or more than 0.0001 PU, using 100 MVA as the base:
      (iii) the nominal high voltage rating of each interconnection circuit branch in kV;
      (iv) the high voltage range that each interconnection circuit branch can be operated over in kV, specified as a maximum and a minimum; and
   (b) for each interconnection transformer branch, the following information:
      (i) the overall 24 hour post contingency capacity rating of the interconnection transformer branch, for both the summer and winter period, in amperes and MVA as follows:
         (A) for 2 Winding interconnection transformer branches, the overall 24 hour post contingency capacity rating in the units described above:
(B) for 3 Winding **interconnection transformer branches**, the overall 24 hour post contingency capacity rating in the units described above, at HV, MV, and LV:

(ii) the continuous capacity rating of the **interconnection transformer branch** in amperes and MVA as follows:

(A) for 2 Winding **interconnection transformer branches**, the continuous capacity rating in the units described above:

(B) for 3 Winding **interconnection transformer branches**, continuous capacity rating in the units described above, at HV, MV, and LV:

(iii) the level of impedance of the **interconnection transformer branch**, both resistive and reactive and for **assets** arranged in both shunt and in series in PU, using a base of 100 MVA, as follows:

(A) for 2 Winding **interconnection transformer branches**, the level of impedance of the **interconnection transformer branch** in the units described above:

(B) for 3 Winding **interconnection transformer branches**, the level of impedance of the **interconnection transformer branch** in the units described above, at HV, MV, and LV:

(iv) the nominal high voltage rating of the **interconnection transformer branch** in kV:

(v) the high voltage range that the **interconnection transformer branch** can be operated over in kV, specified as a maximum, and a minimum:

(vi) in respect of the tapping steps and ranges of the **interconnection transformer branch**:

(A) the tap voltage range in volts, specified as a maximum and a minimum:

(B) the number of tapping steps:

(C) the size of each tapping step as a percentage of the operational voltage range:

(D) whether the tapping step is on-load or off-load:

(E) whether on-load tapping capacity is automatic or manual;

(F) if on-load tapping capacity is automatic, whether it is auto-selected:

(G) if on-load tapping capacity is manual, the tap step it is normally set to, which for the purposes of this rule clause is the actual or expected position at winter peak demand; and

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

(i) DC sent in MW;

(ii) AC received in MW; and

(d) for each **shunt asset**, the following service measures and levels:

(i) the overall capacity rating, in MVAr, in terms of both absorption or provision:

(ii) the nominal voltage rating of the **shunt asset** in kV:

(iii) the maximum and minimum voltage range in kV that the **shunt asset** can operate over; and

(e) in addition to the information required under paragraph (d) in relation to **shunt assets**:

(i) whether each **shunt asset** is dynamic or static:
(ii) if the **shunt asset** is dynamic, whether it is an SVC or synchronous compensator;

(iii) any **shunt assets** that may directly affect the capacity of the **HVDC link** as set out in paragraph (c) and the likely magnitude of such effect; and

(f) the dates for the summer and winter periods or other such defined periods as may apply for the purposes of paragraphs (a) and (b).

(5) The information provided under subclause (4) must,—

(a) in the case of information provided under subclause (4)(a), (c) and (d), must be consistent with the information disclosed by **Transpower** in the most recent **asset capability statement** provided by **Transpower** under clause 2(5) of Technical Code A of Schedule 8.3; and

(b) in the case of information provided under subclause (4)(b), must be consistent with the **manufacturer’s specification** for the component **assets** and the information disclosed by **Transpower** in the most recent **asset capability statement** provided under clause 2(5) of Technical Code A of Schedule 8.3, if this differs from the **manufacturer’s specifications**;

(c) in the case of information provided under subclause (4)(a), must be consistent with the thermal design rating of each **interconnection branch**; and

(d) cover every **interconnection asset**, either as part of an **interconnection circuit branch**, **interconnection transformer branch**, the **HVDC link** or as a **shunt asset**.

(6) After reviewing the interconnection asset capacity and grid configuration provided under subclause (1), the **Authority** may request **Transpower** to reconsider whether any of the interconnection asset capacity and grid configuration, is accurate, and require **Transpower** to resubmit the interconnection asset capacity and grid configuration to the **Authority** for reconsideration.

(8) If **Transpower** believes that it has, or may have, breached subclause (1) or (1A), **Transpower** must report the breach or possible breach to the **Authority** as soon as possible after **Transpower** becomes aware of the breach or possible breach.

12.108 Consultation on proposed interconnection asset capacity and grid configuration

(1) If the **Authority** is provisionally satisfied that the **interconnection asset capacity and grid configuration** provided under clause 12.107(1) or resubmitted under clause 12.107(6) are correct, the **Authority** must publish the proposed **interconnection asset capacity and grid configuration** as soon as practicable for consultation with any person that the **Authority** thinks is likely to be materially affected by the incorporation of the proposed **interconnection asset capacity and grid configuration** by reference in this Code.

(2) As well as the consultation required under subclause (1), the **Authority** may undertake any other consultation it considers necessary.

12.109 Decision on interconnection asset capacity and grid configuration

(1) When the **Authority** has completed its consultation **interconnection asset capacity and grid configuration**, it must consider whether to incorporate the proposed interconnection asset capacity and grid configuration by reference in this Code.
(2) If the Authority decides to incorporate the interconnection asset capacity and grid configuration by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the Act in relation to it.

12.110 Incorporation of interconnection asset capacity and grid configuration by reference

(1) The interconnection asset capacity and grid configuration for the time being in effect is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) 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 interconnection asset capacity and grid configuration becomes incorporated by reference in this Code.

12.111 Transpower to make interconnection branches and other assets available and keep grid configuration

(1) Transpower must make each interconnection circuit branch, interconnection transformer branch, the HVDC link, and each shunt asset identified in the interconnection asset capacity and grid configuration available for use by the system operator for the conveyance of electricity—
   (a) at least at the service levels specified in the interconnection asset capacity and grid configuration in accordance with clause 12.107(4); and
   (b) in accordance with good electricity industry practice and relevant health and safety standards.

(2) Transpower must keep the grid in the configuration set out in the interconnection asset capacity and grid configuration.

(3) Transpower is not required to comply with subclauses (1)(a) or (2) if clause 12.112(1) applies.

(4) If Transpower believes that it has, or may have, breached subclause (1)(a) or (2), and clause 12.112(1) does not apply, or has, or may have, breached clauses 12.107(1) or 12.107(1A), Transpower must report the breach or possible breach to the Authority as soon as possible after Transpower becomes aware of the breach or possible breach.

12.112 Exceptions to clause 12.111

(1) Transpower is not required to comply with clause 12.111(1)(a) or (2) if—
   (a) permitted under the Outage Protocol made under subpart 7; or
   (b) an interconnection asset that forms part of an interconnection branch or the HVDC link, or a shunt asset—
      (i) is permanently removed from service, the grid is permanently reconfigured, or the transmission capacity of such an asset is reduced, and the decision to remove the asset from service or reconfigure the grid or reduce the transmission capacity of the asset takes into account the effect of the removal of the asset, reconfiguration of the grid, or the reduction in transmission capacity of the asset, on other materially affected parties, and is undertaken—
         (A) in order to maintain the health and safety of any person; or
         (B) in order to maintain the safety and integrity of equipment; or
         (C) in accordance with demonstrably prudent economic criteria; or
(iaa) has been temporarily removed from service, or the grid has been temporarily reconfigured, in accordance with clause 12.116AA; or

(ia) [Expired]

(ii) has been permanently removed from service, or the grid has been permanently reconfigured, in accordance with clause 12.117; or

(c) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid, has been made as a result of an investment in the grid; or

(d) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid has been made as a result of an investment made under an investment contract entered into in accordance with clauses 12.70 and 12.71; or

(e) the voltage range specified in the AOPOS for an interconnection asset that forms part of an interconnection branch is modified, or any equivalence arrangement is approved or dispensation is granted under clauses 8.29 to 8.31 in respect of the asset; or

(ea) in relation to the HVDC link—

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

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

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

(ii) the configuration of the HVDC link is—

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

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

(f) Transpower and a designated transmission customer have agreed otherwise in accordance with clause 12.128.

(2) If subclauses (1)(c) to (e) apply, or the grid is reconfigured under subclause (1)(b)(i) or (ii), Transpower must—

(a) make the interconnection branch, the HVDC link or the shunt asset available to the system operator at least at its modified capacity rating, and at its modified service levels; and

(b) keep the grid in its modified configuration.

(4) If Transpower believes that it has, or may have, breached subclause (2), Transpower must report the breach or possible breach to the Authority as soon as possible after Transpower becomes aware of the breach or possible breach.

12.116 Information on capacities of individual interconnection assets

(1) Transpower must publish the following information in respect of each interconnection asset:

(a) for each transformer that is an interconnection asset, the overall 24 hour post contingency capacity rating of the asset in amperes and MVA, for both the summer and winter periods:

(b) for all other interconnection assets, the overall capacity rating of the asset in amperes and MVA and, if the interconnection assets are circuits, for both the summer and winter periods.
(2) The information required under subclause (1)—
(a) must be consistent with the manufacturer's specification for the asset or with the most recent asset capability statement provided by Transpower under clause 2(5) of Technical Code A of Schedule 8.3, if this differs from the manufacturer's specification; and
(b) must be provided in a form that allows the branch to which each asset belongs to be easily identified; and
(c) must be published in the form determined by the Authority as soon as reasonably practicable after the Authority has determined the form.

12.116AA Temporary removal of interconnection assets from service or temporary grid reconfiguration
(1) Transpower must temporarily remove 1 or more interconnection assets from service, or temporarily reconfigure the grid for the purposes of as permitted under clause 12.112(1)(b)(iaa), if—
(a) the removal or reconfiguration is requested by the system operator in accordance with clause 9.13B; and
(b) the removal or reconfiguration will result in a net benefit, as calculated under the test set out in clause 12.117.
(2) If Transpower temporarily removes interconnection assets from service or temporarily reconfigures the grid in response to a notice given under clause 9.13B, Transpower must, as soon as is reasonably practicable after the circumstances specified in that notice cease to exist—
(a) restore the interconnection assets to service; or
(b) restore the grid to its original configuration.

12.117 Permanent removal of interconnection assets from service
(1) Transpower may permanently remove interconnection assets from service or permanently reconfigure the grid for the purposes of as permitted under clause 12.112(1)(b) only if removal of the asset or the reconfiguration of the grid results in a net benefit, as calculated under the test set out in subclause (2).

12.118 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration
(1) Transpower must provide the Authority with and publish an annual report including—
(a) any matter required to be reported on for the purposes of this clause by the Outage Protocol; and
(b) the extent to which, in the preceding year, it has complied with the requirements of clause 12.111(1)(a) and (2); and
(c) any specific instances in which Transpower has not complied with clause 12.111(1)(a) and (2); and
(d) to the extent practicable, the circumstances that have given rise to any failure to comply with clause 12.111(1)(a) and (2); and
(e) to the extent practicable, any steps that it intends to take or other options to reduce the likelihood of failing to comply with clause 12.111(1)(a) and (2) in the future; and
(f) any modifications made to interconnection circuit branches, the HVDC link, and
each shunt asset under clause 12.112(c) to (e) in the preceding year and the extent to which it has complied with clause 12.112(2) in respect of those modifications, including any specific instances in which Transpower has not complied; and

(g) any interconnection assets that have been removed from service, or any reconfigurations to the grid made, in accordance with clause 12.116AA or clause 12.117; and

(h) copies of any agreements made under clause 12.128 or, in respect of interconnection assets only, clause 12.151 in the preceding year; and

(i) an update of the interconnection asset capacity and grid configuration required under clause 12.107(1), as at the end of the preceding year.

(2) The report referred to in subclause (1) must be provided and published by Transpower by 30 November each year.

(3) The Authority may incorporate by reference in this Code the updated interconnection asset capacity and grid configuration referred to in subclause (1)(i) in accordance with clause 12.110. The Authority may consult with any person the Authority considers is likely to be materially affected by the proposed amendments to the interconnection asset capacity and grid configuration, as it sees fit. Transpower must comply with the interconnection asset capacity and grid configuration incorporated by reference in this Code in accordance with clause 12.110.

12.128 Transpower and designated transmission customers may agree on other requirements

(1) Transpower and each designated transmission customer must comply with this Part, unless agreed otherwise by Transpower and the designated transmission customer in respect of specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer in accordance with subclause (2).

(2) An agreement between Transpower and a designated transmission customer under this clause may not exclude the application of clause (3)(b) or clause 12.151(3) 12.118(1)(h) and must be conditional in all respects on—

(a) obtaining agreement from all other potentially affected designated transmission customers that this Part does not apply to the specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer; and

(b) Transpower and the designated transmission customer certifying to the Authority that they have consulted with all potentially affected end use customers on this Part not applying to the specified interconnection branches, circuit branches, the HVDC link, shunt assets or interconnection assets or the designated transmission customer, and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must—

(a) notify the Authority as soon as practicable in the event that if Transpower enters into an agreement with a designated transmission customer under this clause; and

(b) publish the agreement on its website no later than 20 business days after entering into the agreement.
12.151 Compliance with Outage Protocol

(1) Transpower and each designated transmission customer must comply with the Outage Protocol, unless agreed otherwise by Transpower and a designated transmission customer in respect of specified assets or the designated transmission customer in accordance with subclause (2).

(2) An agreement between Transpower and a designated transmission customer to which the Outage Protocol does not apply in respect of specified assets must not exclude the application of subclause 3(b) 12.118(1)(b) and must be conditional in all respects on—
   (a) obtaining agreement from all other potentially affected designated transmission customers that the Outage Protocol does not apply in respect of the specified assets or the designated transmission customer; and
   (b) Transpower and the designated transmission customer satisfying the Authority that they have consulted with all potentially affected end use customers on the Outage Protocol not applying in respect of the specified assets or the designated transmission customer and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must—
   (a) notify the Authority as soon as practicable if Transpower enters into an agreement with a designated transmission customer in respect of specified assets in accordance with subclause (1); and
   (b) publish the agreement on its website no later than 20 business days after entering into the agreement.
CRP 2016-10  Simplifying Code terms about time

Part 1

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

financial year means the 12-month period beginning on the date determined by the Authority

preceding year, for the purposes of Part 12, means the period from 1 July in a year to 30 June in the following year, preceding the date by which Transpower is required to publish information under either clauses 12.118 or 12.127, as the case may be

preceding year day means the day preceding the relevant trading day by 364 days, but—
(a) if the relevant trading day is a national holiday, the preceding year day will be deemed to be the Sunday before the 364th day;
(b) if the relevant trading day is a business day, but the 364th day before it is a national holiday, the preceding year day is deemed to be the next business day after the national holiday

qualifying date means the day after the last day of a public conservation period

working day means any day of the week other than—
(a) Saturdays, Sundays, and national holidays; and
(b) a day in the period commencing on 25 December in any year and ending on 15 January in the following year

year means a year commencing on the 1st day of April of each calendar year and expiring on the 31st day of March of the following calendar year

Part 2

2.8 Transfer of requests

(2) The participant to which the notice was sent must promptly, and in any case not later than 10 working business days after the day on which the notice is received, transfer the notice to the other participant, and inform the Authority accordingly.

Part 3

3.12 Performance standards to be agreed

The Authority and the relevant market operation service provider must, at the beginning of each financial year ending 30 June, seek to agree on a set of performance standards
against which the market operation service provider’s actual performance must be reported and measured at the end of the financial year ending 30 June.

3.14 Market operation service providers must report to Authority
(1) Each market operation service provider must, within 10 working business days after the end of each calendar month (except within 20 business days of the end of the month of December), provide a written report to the Authority on the results of the review carried out under clause 3.13.

3.15 Review of market operation service providers
(1) At the end of each financial year ending 30 June, the Authority may review the manner in which each market operation service provider has performed its duties and obligations under this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act.

Part 7

7.2E System operator to report on frequency fluctuations
(1) By the 10th working business day of each month (except by the 20th business day in the month of January), the system operator must report to the Authority the number of frequency fluctuations in each of the following frequency bands, in each island in the previous month:

<table>
<thead>
<tr>
<th>Frequency band (Hertz) (where &quot;x&quot; is the maximum or minimum frequency during a frequency fluctuation)</th>
<th>52.00</th>
<th>&gt; x ≥ 51.25</th>
</tr>
</thead>
<tbody>
<tr>
<td>51.25</td>
<td>&gt; x ≥ 50.50</td>
<td></td>
</tr>
<tr>
<td>49.50</td>
<td>&gt; x ≥ 48.75</td>
<td></td>
</tr>
<tr>
<td>48.75</td>
<td>&gt; x ≥ 48.00</td>
<td></td>
</tr>
<tr>
<td>48.00</td>
<td>&gt; x ≥ 47.00</td>
<td></td>
</tr>
</tbody>
</table>

(2) By the 10th working business day of each month (except by the 20th business day in the month of January), the system operator must report to the Authority the number of frequency fluctuations in each of the following frequency bands, in the South Island in the previous month:

| Frequency band (Hertz) (where "x" is the maximum or minimum frequency during a frequency fluctuation) | 55.00 | > x ≥ 53.75 |
7.8 Review of system operator
(1) The Authority must review the performance of the system operator at least once in each financial year ending 30 June, after the system operator submits its self-review under clause 7.11.

7.12 Authority must publicise system operator reports
…
(2) The Authority must publicise each report within 5 working business days after receiving the report.

Part 9

9.5 Amendments and substitutions of system operator rolling outage plans
…
(3) The system operator must not submit an amended or new system operator rolling outage plan to the Authority under clause 9.2(2) unless the system operator has—
(a) consulted with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by the amended or new plan; and
(b) considered submissions made on the amended or new plan.

(4) Subclause (3) does not apply if the system operator considers that it is necessary or desirable in the public interest that the proposed system operator rolling outage plan be published urgently, and, in this case, the system operator rolling outage plan, and the notice in the Gazette that is part of the publishing of the plan, must state that the plan is published in reliance on this subclause and then, within 6 months of the plan being published, the system operator must—
(a) comply with subclause (3); and
(b) decide whether or not the plan should be amended or revoked and a new plan substituted; and
(c) no later than 10 working business days after making that decision, publish the decision; and
(d) if the system operator decides that the plan should be amended or revoked and a new plan substituted, comply with this clause in relation to the proposed amendment or revocation and substitution.

9.10 Revision of participant rolling outage plans
If the system operator declines to approve a participant rolling outage plan,—
(a) the system operator must—
   (i) indicate the grounds on which it declines to approve the plan; and
   (ii) direct the specified participant to submit a revised plan; and
(b) the **specified participant** must submit a revised plan to the **system operator** no later than—

(i) 15 **working-business days** after the date on which the **specified participant** received the direction from the **system operator** to submit a revised plan; or

(ii) any later date that the **system operator** may allow in any particular case.

9.13 **Specified participants must keep participant rolling outage plans up to date**

(1) Each **specified participant** who has had a **participant rolling outage plan** approved under clauses 9.6 to 9.12 must—

(a) keep the plan under review, and (if necessary) amend the plan to take account of any change of circumstances and to ensure that the plan continues to comply with clause 9.8; and

(b) as soon as practicable after amending the plan, but in any case no later than 20 **working-business days** after amending it, submit the plan to the **system operator**.

…

(3) A plan submitted to the **system operator** under subclause (1)(b) is deemed to be approved by the **system operator** unless, no later than 20 **working-business days** after the **system operator** receives the plan, the **system operator** advises the **specified participant** who submitted the plan, by notice in writing, that it declines to approve the plan.

9.21 **Qualifying customers**

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

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

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

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

(ii) there was consumption, in the **previous year** 12 months immediately preceding the **public conservation period**, of 3000 kWh or more.

…

(3) For the purposes of subclause (1)(b)(ii), if a **qualifying customer’s previous year’s** consumption at the ICP in the 12 months immediately preceding the **public conservation period** is not available to the **retailer**, the **retailer** must make a reasonable estimate of the consumption.

(4) To avoid doubt,—

(a) there is no **qualifying customer** at an ICP if, at the end of the last day of a **public conservation period** qualifying date, —

(i) the premises to which the ICP is connected are vacant; or

(ii) the ICP is disconnected:

(b) a **retailer’s qualifying customers** includes a **customer** who switched—

(i) to the **retailer** from another **retailer** on or before the last day of a **public conservation period** qualifying date, including during that **public conservation period**; or
(ii) from the retailer to another retailer between the last day of a public conservation period qualifying date and the date on which the retailer pays compensation under the customer compensation scheme.

9.24 Requirements of default customer compensation schemes
(1) A retailer’s default customer compensation scheme must provide for the retailer—

(c) to pay at least the minimum weekly amount—

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

(ii) no later than the end of 2 billing periods after the last day of a public conservation period qualifying date.

9.25 Authority must determine minimum weekly amount
(1) In determining the minimum weekly amount that each retailer must pay to its qualifying customers, the Authority must take into account—

(a) the estimated value, in dollars/MWh, of the savings that the Authority expects all qualifying customers in the South Island or New Zealand, as the case may be, of all retailers, will achieve during an official conservation campaign; and

(b) any other factors that the Authority considers relevant.

(2) The Authority must—

(a) publicise the minimum weekly amount; and

(b) review the minimum weekly amount—

(i) after each public conservation period ends; and

(ii) at least once every 3 calendar years; and

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

Part 10

Schedule 10.2
1 Auditors

... (5) The Authority has not more than 2 calendar months from the date on which it receives a completed application, to assess and, if in the Authority’s view it is appropriate, to approve the application.

Schedule 10.3

1 Applications for approval and renewal of approval

... (4) If an application is approved, the Authority must issue a certificate of approval specifying the—

(a) period of the term of approval, which must not exceed 12 calendar months from the date of approval; and
Schedule 10.5

1 Metering equipment provider must ensure audits are carried out
(1) A metering equipment provider must—
   (a) ensure that an initial audit by an auditor under subclause (2) is completed—
   (i) in the case of a participant who becomes a metering equipment provider on or after 29 August 2013, within 3 calendar months after the date on which the metering equipment provider first becomes a metering equipment provider; or…

Schedule 10.7

14 Insufficient load for metering installation certification tests
   …
   (3) A metering equipment provider must, for each metering installation for which it is responsible, and that is certified under this clause, obtain and monitor raw meter data from the metering installation at least once each calendar month during the period of certification to determine if load during the month is sufficient for a prevailing load test to be completed.

11.10 Distributors’ processes to be audited
   (1) Each distributor must arrange for the conduct of audits by an auditor, and provide final audit reports to the Authority as follows:
   (a) an initial audit completed within 3 calendar months after the date on which the distributor has the first NSP identifier or ICP identifier recorded on the registry as being part of the distributor’s network:

11.25 Reports to the clearing manager, system operator or reconciliation manager
   …
   (4) If the request is received by the time specified in this clause, the registry must provide the report by 1000 hours on the 1st business day of the calendar month following the calendar month in which the request was made, or if the request for the report specifies a later date, by the later date.
   …
   (6) The registry must comply with a request made in accordance with subclause (5) by 1000 hours on the 1st business day of the calendar month following the calendar month in which the request was made.

11.26 Reports to the reconciliation manager
   By 1600 hours on the 4th business day of each calendar month, in respect of the immediately preceding consumption period, and by 1600 hours on the 13th business day of each calendar month in respect of the immediately preceding 14 consumption periods, the registry must deliver the following reports to the reconciliation manager:
11.27 Reports to the market administrator
By 1600 hours on the 1st business day of each calendar month, the registry must deliver to the market administrator a report summarising the number of events that have not been notified to the registry, of which it is aware, within the timeframes specified in this Part.

11.32C Retailers must notify consumers of availability of information
Each retailer must notify each consumer with whom it has a contract to supply electricity of the consumer's ability to make a request to the retailer under clause 11.32B, so that the consumer is notified at least once in each calendar year.

Schedule 11.1
...
15 "New" or "Ready" status for 24 calendar months or more
(1) Subclause (2) applies if—
(a) an ICP has had the status of "New" for 24 calendar months or more; or
(b) an ICP has had the status of "Ready" for 24 calendar months or more.
...
26 Information to be provided if NSPs are created or ICPs are transferred from 1 distributor's network to another distributor's network
...
(2) The participant must make the request—
(b) in every other case, at least 1 calendar month before the NSP is electrically connected or the ICP is transferred.
...
(5) The distributor must give the notification at least 1 calendar month before the creation or transfer.
...
27 Information to be provided if ICPs become NSPs
...
(2) The distributor must give the notification at least 1 calendar month before the transfer.
...
29 Obligations concerning change in network owner
...
(2) The network owner must give the notification at least 1 calendar month before the acquisition.

Schedule 11.3
...
4 Event dates
...
(2) When establishing an event date under this clause, the losing trader must disregard every event date established by the losing trader for a customer who, at the time that the event date is established, has been a customer of the losing trader for less than 2 calendar months.
12.20 Required content of Connection Code

The Connection Code must provide for the following matters:

(a) connection requirements for designated transmission customers;
(b) technical requirements for assets, including assets owned by Transpower, and for other equipment and plant that is connected to a local network or an embedded network or that forms part of an embedded network or embedded generating station if the operation of that equipment and plant could affect the grid assets;
(c) operating standards for equipment that is owned by a designated transmission customer, used in connection with the conveyance of electricity, and that is situated on land owned by Transpower;
(d) information requirements to be met by designated transmission customers before equipment is connected to the grid and before changes are made to the equipment;
(e) an obligation on Transpower to provide a 10 year forecast of the expected maximum fault level of each point of service to designated transmission customers set out in the transmission agreement between Transpower and each designated transmission customer.

12.76 Transpower to publish grid reliability report

(1) Transpower must publish a grid reliability report setting out—

(a) a forecast of demand at each grid exit point over the next 10 years ending 31 December years; and
(b) a forecast of supply at each grid injection point over the next 10 years ending 31 December years; and
(c) whether the power system is reasonably expected to meet the N-1 criterion, including in particular whether the power system would be in a secure state at each grid exit point, at all times over the next 10 years ending 31 December years; and
(d) proposals for addressing any matters identified in accordance with paragraph (c).

(2) Transpower must publish a grid reliability report no later than 2 years after the date on which it published the previous grid reliability report, or such other date as determined by the Authority (having consulted with Transpower).

12.118 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration

(1) Transpower must provide the Authority with and publish an annual report including—

(a) any matter required to be reported on for the purposes of this clause by the Outage Protocol; and
(b) the extent to which, in the preceding year ending 30 June, it has complied with the requirements of clause 12.111(1)(a) and (2); and
(c) any specific instances in which Transpower has not complied with clause 12.111(1)(a) and (2); and
(d) to the extent practicable, the circumstances that have given rise to any failure to comply with clause 12.111(1)(a) and (2); and
(e) to the extent practicable, any steps that it intends to take or other options to reduce the likelihood of failing to comply with clause 12.111(1)(a) and (2) in the future; and
(f) any modifications made to interconnection circuit branches, the HVDC link, and
each shunt asset under clause 12.112(c) to (e) in the preceding year ending 30 June and the extent to which it has complied with clause 12.112(2) in respect of those modifications, including any specific instances in which Transpower has not complied; and

(g) any interconnection assets that have been removed from service, or any reconfigurations to the grid made, in accordance with clause 12.116AA or clause 12.117; and

(h) copies of any agreements made under clause 12.128 or, in respect of interconnection assets only, clause 12.151 in the preceding year ending 30 June; and

(i) an update of the interconnection asset capacity and grid configuration required under clause 12.107(1), as at the end of the preceding year ending 30 June.

12.121 Transpower to submit draft index measures for availability and reliability

…

(3) The index measures to be provided under subclause (1) are—

(a) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to planned outages of 1 minute or longer in hours per year ending 30 June year, expressed as a percentage; and

(b) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to unplanned outages of 1 minute or longer in hours per year ending 30 June-year, expressed as a percentage; and

(c) annual number of planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link; and

(d) annual number of unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link;

(e) total unserved energy per year ending 30 June-year in MWh resulting from planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link; and

(f) total unserved energy per year ending 30 June-year in MWh resulting from unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link.

12.122 Requirements for index measures

(1) The proposed availability and reliability index measures under clause 12.121(3) must be based on the average annual availability and reliability of each category of interconnection branch, or shunt asset and of the HVDC link over the 5 year period (being 1 July to 30 June years) immediately before this clause came into force.
12.127 Transpower to report on availability and reliability

(1) By 30 November in each year, Transpower must publish and provide to the Authority information on availability and reliability of interconnection assets including—

(a) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to planned outages of 1 minute or longer in the preceding year ending 30 June in hours per year, expressed as a percentage; and
(b) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to unplanned outages of 1 minute or longer in the preceding year ending 30 June in hours per year, expressed as a percentage; and
(c) annual number of planned interruptions of 1 minute or longer caused by planned outages of one minute or longer of each interconnection branch, shunt asset and the HVDC link in the preceding year ending 30 June; and
(d) annual number of unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link in the preceding year ending 30 June; and
(e) total unserved energy in the preceding year ending 30 June resulting from planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of interconnection branches, shunt assets and the HVDC link; and
(f) total unserved energy in the preceding year ending 30 June resulting from unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of interconnection branches, shunt assets and the HVDC link; and
(g) annual number of outages of each interconnection branch, shunt asset and the HVDC link that are shorter than 1 minute in the preceding year ending 30 June; and
(h) the annual number of interruptions shorter than 1 minute caused by outages that are shorter than 1 minute of each interconnection branch, shunt asset and the HVDC link, in the preceding year ending 30 June; and
(i) a comparison of the information required by paragraphs (a) to (f) against the availability and reliability index measures for interconnection branches, shunt assets and the HVDC link included in a schedule to this Part under clause 12.126;
(j) to the extent practicable, an explanation of the reasons for not meeting the reliability and availability index measures for interconnection branches, shunt assets and the HVDC link included in a schedule to this Part under clause 12.126 and any steps or other options it intends to take in future to meet the index measures; and
(k) information on its performance against the reliability and availability index measures for aggregated interconnection branches included in a schedule to this Part under clause 12.126.

12.135 Required content of Outage Protocol

... (4) The Outage Protocol must set out—
(a) processes for Transpower to consult with designated transmission customers and to determine an outage plan setting out planned outages for each year ending 30 June, and processes for the outage plan to be updated; and
(b) requirements on Transpower to keep designated transmission customers informed about planned outages, including minimum notice periods for Transpower to advise affected designated transmission customers of planned outages not set out in the outage plan; and
(c) procedures for outage co-ordination by Transpower and between Transpower and designated transmission customers; and
(d) requirements on Transpower to provide information to designated transmission customers about unplanned outages.

Part 13

13.27J New GXP
At least 1 calendar month before a grid owner connects a GXP to the grid for the first time, the grid owner must advise the Authority in writing of its intention to connect the GXP.

13.102 Reporting obligations of system operator
By the 10th business day of each calendar month, the system operator must inform the Authority in writing of any discretionary action the system operator has taken under clause 13.70, in the previous calendar month, that required departure from the dispatch schedule.

13.119 Historic load data
(1) Subject to subclauses (2) and (3), by 1100 hours 2 days before each auction, each grid owner must advise the clearing manager the total load of the preceding year day-day preceding by 364 days for the day following the auction.
(2) If the day following the auction is a national holiday, the day for which load must be advised is deemed to be the Sunday before the 364th day.
(3) If the day following the auction is a business day, but the 364th day before it is a national holiday, the day for which load must be advised is deemed to be the next business day after that national holiday.

13.120 Quantity available for auction
The clearing manager must calculate the quantity of auction rights available in each time block at each auction as follows:

\[
\text{quantity of auction rights available in each time block} = 0.8 \times \text{ldf}_{tb}
\]

where

\( \text{ldf}_{tb} \) is the lowest demand forecast for a time block, which is the lowest demand in any trading period on the preceding year day-day for which load must be advised under clause 13.119 (in an interval that equates to the time block)
13.214 Market administrator to publish pricing manager reports

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

(2) By the 15th business day of each calendar month the market administrator must refer the reports received in the previous calendar month to the Authority.

13.230 Certification of information

(1) Each participant who has submitted information to the information system in accordance with clause 13.225 in a particular year ending 31 March year must provide, within 3 months of the year ending 31 March end of the year, a certificate to the Authority verifying that the information submitted was correct.

13.236A Disclosing participants must prepare and submit spot price risk disclosure statements

(1) Each disclosing participant must prepare a spot price disclosure statement for each quarter beginning 1 January, 1 April, 1 July, and 1 October in each calendar year.

(3) The disclosing participant must submit the spot price risk disclosure statement to the person appointed by the Authority to receive spot price risk disclosure statements no later than 5 working business days before the beginning of the quarter to which the statement relates.

13.236D Authority must publicise base case, stress test, and method for calculating target cover ratio

(2) If the Authority has not publicised a notice under subclause (1) at least 30 working business days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, a disclosing participant is not required to prepare or submit a spot price risk disclosure statement for the next quarter.

(3) If the Authority publicises an amendment to a notice, or revokes and replaces a notice, within 30 working business days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, disclosing participants must prepare spot price risk disclosure statements for the immediately following quarter in accordance with the notice as in force immediately before the amendment or replacement was made and not in accordance with the notice as amended or replaced.

13.236E Content of spot price risk disclosure statements

(3) The disclosing participant must ensure that a spot price risk disclosure statement is signed and dated by a director, or the chief executive officer, or the chief financial officer, or a person holding a position equivalent to one of those positions, of the disclosing participant no earlier than 20 working business days and no later than 5 working business days before the beginning of the quarter to which the statement relates.
13.236G Authority may require disclosing participant to submit new spot price risk disclosure statement

(2) If a disclosing participant receives a request from the Authority under subclause (1), the disclosing participant must submit a new spot price risk disclosure statement to the person appointed by the Authority to receive spot price risk disclosure statements within 10 working business days after the date on which the disclosing participant received the request.

13.236H Authority may require independent audit of spot price risk disclosure statement or certificate

(5) If the disclosing participant fails to nominate an appropriate auditor within 5 working business days, the Authority may direct the disclosing participant to appoint an auditor of the Authority's choice.

(8) The disclosing participant must provide the information no later than 10 working business days after receiving a request from the auditor for the information.

Part 14

14.18 Clearing manager to advise participant of amounts owing and payable

(2) The clearing manager must advise each participant of each amount owing and each amount payable as follows:

(a) no later than the 9th business day of the month following the billing period; but
(b) if the clearing manager has not received any information required to determine an amount payable in respect of the prior billing period in time to advise each participant by that date,—

(i) if the clearing manager receives the information in time to advise each participant of each amount owing and each amount payable 2 business days or more before the 20th calendar day of the month, the clearing manager must advise each participant no later than 2 business days before the 20th calendar day of the month; or

(ii) if the clearing manager does not receive, or considers that it is not likely to receive, the information in time to advise each participant of each amount owing and each amount payable 2 business days before the 20th calendar day of the month,—

(A) the clearing manager must refer the matter to the Authority; and

(B) the Authority must direct the clearing manager as to the time by which the clearing manager must advise each participant of each amount owing and each amount payable; and

(C) the clearing manager must advise each participant by the time directed by the Authority.
14.31 Deadlines for payments
(1) Subject to subclauses (3) and (4), each participant must pay the clearing manager the amount advised to the participant under subpart 4 as payable by the participant to the clearing manager by—
(a) 1300 hours on the 20th calendar day of the month following the billing period in respect of which the amount was advised; or
(b) if that day is not a business day, 1300 hours on the next business day.

14.68 Monthly divergence reports to be prepared by clearing manager
…
(2) The clearing manager must give the report to the market administrator—
(a) on the 10th business day of each calendar month; or
…

14.69 Market administrator to publish clearing manager reports
(1) By the 15th business day of each calendar month, the market administrator must publish the sections of the report, received in the previous calendar month from the clearing manager in accordance with clause 14.68, that relate to any breaches of this Code by the clearing manager.
(2) By the 15th business day of each calendar month the market administrator must also refer the report received in the previous calendar month to the Authority.

Part 15

15.14 Notification of changes to the grid
…
(2) The grid owner must give the notice at least 1 calendar month before the effective date of the intended change.

Schedule 15.1
…
7 Renewal of certification
(1) Certification must not be granted for a term of more than 12 calendar months.
(2) The Authority must renew a reconciliation participant’s certification for a further term of not more than 12 calendar months if the Authority is satisfied on the basis of an audit report provided to the Authority under clause 11 that the reconciliation participant continues to meet the requirements specified in clause 5.
…
9 Auditors
…
(5) The Authority has not more than 2 calendar months from the date on which the completed application is received by the Authority, to assess, and if in the Authority’s view it is appropriate, to approve, the application.

Schedule 15.5
28 Sampling requirements

…

(2) For profiles that require statistical sampling, the market administrator must specify the preliminary sample size and draw a preliminary sample of ICP identifiers from the profile population list, or must accept appropriate sampling performed by the profile applicant. Half hour research meters must be, or must have been, installed and operated by the profile applicant for this preliminary sample. The market administrator must require a minimum sampling period of 60 calendar days, and not more than 12 months. The market administrator may withdraw ICP identifiers from the profile population list if it can be shown by the profile applicant that those ICP identifiers are in sites that are difficult to meter.

Schedule 15.5, Appendix 2

2 Preliminary sample

…

(8) The profile applicant must collect half hour data from the preliminary sample over a period of at least 60 calendar days. The data, in its processed form, must be submitted to the market administrator for consideration. The data processing must include calculations of unit costs, and of mean and standard deviation of unit costs, over the sample period.
CRP 2016-11  Rationalising references to registry and registry manager

Part 1

gaining metering equipment provider means, for the purposes of Parts 10 and 11,—
(a) the person who a trader advises the registry manager may become the metering equipment provider for each metering installation for a point of connection; or

loss category means the relevant code in the schedule published by the registry manager that identifies the relevant loss factors that apply to submission information or dispatchable load information

loss factor means the factor, identified by reference to a loss category within the registry, to be applied to submission information or dispatchable load information to obtain adjusted for losses information at the relevant NSP, which factor is—
(a) as set out in the report to be provided by the registry manager in accordance with clause 11.26(b); or
(b) if a report has not been provided by the registry manager, as directed by the Authority under clause 15.20B(3) or 15(1) of Schedule 15.4

registry and registry manager means the database maintained by the Authority to record information about ICPs person or persons for the time being appointed as the registry manager under this Code

registry manager means the market operation service provider who is for the time being appointed as registry manager under this Code

retailer means as follows:
(a) except as provided in paragraphs (b) and (c), a participant who supplies electricity to another person for any purpose other than for resupply by the other person:
(b) in Parts 1 (except for the definition of specified participant), 8, 10, and 12 to 15, a participant who supplies electricity to a consumer or to another retailer:
(c) in subpart 4 of Part 9, the retailer defined in paragraph (a) who is recorded by in the registry manager as being responsible for the ICP described in clause 9.21(1)(b)

Part 6

Schedule 6.2

15 Permanent disconnection

(1) Despite clause 10, the distributor may permanently disconnect distributed generation in the following circumstances:

... without notice, if the trader that is recorded in the registry as being responsible for the ICP to which the distributed generation is connected to the distribution network has de-energised the ICP and advised the registry manager that the ICP has a status of "inactive" with the reason of "de-energised – ready for decommissioning":

132
Part 10

10.19 Metering equipment provider

... (2) The metering equipment provider for each category 1 metering installation, or higher category of metering installation for a point of connection, other than a metering installation referred to in subclause (1),—
(a) that is an ICP and not also an NSP, is the person who advises the registry manager that it accepts responsibility as the metering equipment provider under clause 1(1)(a)(ii) of Schedule 11.4:

10.22 Change of metering equipment provider

(1) The metering equipment provider for a metering installation may change only if the participant responsible for ensuring there is a metering installation under clause 10.24, 10.25, or 10.26 enters into an arrangement with another person to become the metering equipment provider for the metering installation and—
(a) in the case of a metering installation for an ICP that is not also an NSP—
(i) the trader for the metering installation advises the registry manager of the gaining metering equipment provider in accordance with Part 11; and
(ii) the gaining metering equipment provider advises the registry manager that it accepts becoming the metering equipment provider (including the effective date from which the gaining metering equipment provider assumes its responsibility as metering equipment provider for the metering installation) in accordance with Part 11; or

Schedule 10.5

1 Metering equipment provider must ensure audits are carried out

... (2) A metering equipment provider must ensure an auditor carrying out an audit under subclause (1) audits the following processes and procedures:

... (b) the metering equipment provider’s provision of metering records to—
(i) the registry manager

Schedule 10.7

24 Compensation factors

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

... (b) in all other cases, advise the registry manager of the compensation factor in accordance with Part 11.

32 Alternative certification requirements for metering installation incorporating measuring transformer

(1) An ATH may, if it cannot comply with the requirements of clause 2 of Schedule 10.8 due solely to its inability to obtain physical access to test an installed measuring transformer
in a metering installation, certify the metering installation for a period not exceeding 24 months, if—

... (d) the metering equipment provider has advised the registry manager of the certification under this clause.

44 General inspection requirements

... (5) A metering equipment provider must, within 20 business days of receiving the inspection report,—

... (c) advise the registry manager of the relevant changes.

Part 11

11.1 Contents of this Part

This Part—
(a) provides for the management of information held by in the registry; and

11.7 Provision of ICP information

(1) A distributor whose network includes 1 or more ICPs must provide information about each of those ICPs to the registry manager in accordance with Schedule 11.1.
(2) A trader must provide information about each ICP at which the trader trades electricity to the registry manager in accordance with Schedule 11.1.

11.8A Metering equipment providers to provide registry metering records to registry manager

(1) A metering equipment provider must, for each metering installation described in subclause (2) for which it is responsible,—
(a) provide to the registry manager the registry metering records for the metering installation in the prescribed form; and

11.10 Distributors’ processes to be audited

... (4) The distributor’s processes and procedures that must be audited include—
... (b) the provision of ICP information to the registry manager and the maintenance of that information; and

11.14 Process for maintaining shared unmetered load

... (2) The distributor must notify 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.
A distributor who receives notification under subclause (3) must notify 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.

11.15A Application of Schedule 11.4
The following parties must comply with Schedule 11.4:
(a) a trader who notifies the registry manager of the gaining metering equipment provider responsible for each metering installation for an ICP;
(b) the registry manager:
...

11.16 Trader to ensure arrangements for line function services and metering
Before providing the registry manager with information in accordance with clause 11.7(2) or clause 11.18(4), a trader must—
...

11.18A Registry manager to advise metering equipment providers
The registry manager must, within 1 business day of being advised by a trader of a metering equipment provider's participant identifier for an ICP identifier, —
(a) if there is not already a metering equipment provider assigned to the ICP identifier, advise the gaining metering equipment provider that the registry manager has been advised that it is the gaining metering equipment provider for each metering installation for the ICP; or
...

11.20 Registry must be available open between 0730 and 1930 each day
(1) The registry manager must ensure that the registry is be available to receive and provide information under this Part between 0730 hours and 1930 hours each day.
(2) Information provided to the registry manager after 1930 hours is deemed to be provided at 0730 the next day.

11.21 Confirmation of receipt of data
(1) Information provided to the registry manager is deemed, for the purposes of this Part, not to have been received until the registry manager has confirmed receipt in accordance with this clause.
(2) The registry manager must confirm receipt of information received by it in accordance with this Part within 4 hours of the information being provided to it.
(3) In determining whether the registry manager has confirmed receipt within the time specified in subclause (2), no account is to be taken of any period during which the registry is not required to be available under clause 11.20.
(3) Time when the registry is not obliged to be available in accordance with clause 11.20 will not be taken into account in determining whether or not receipt has been confirmed within 4 hours.
(4) If the participant providing the information does not receive confirmation that the registry manager has received the participant's information, the participant must contact the registry manager to check whether the registry manager information has been received the information.
If the registry manager has not received the information, the participant must re-send the information. This process must be repeated until the registry manager has confirmed receipt of the information in accordance with this clause.

11.22 Registry manager must maintain a register database of information
(1) The registry manager must maintain a register of information received by it and updated in accordance with this Code.
(2) The registry manager must ensure that a complete audit trail exists for all information received by it in accordance with this Code.

11.23 Reports from the registry manager
By 1600 hours on the 6th business day of each reconciliation period, the registry manager must publish a report containing the following information:
(a) the number of ICPs notified to the registry manager and contained on its register at the end of the immediately preceding consumption period;
(b) the number of notifications received by the registry manager in accordance with clause 2 of Schedule 11.3 during the previous reconciliation period;
(c) such other information as may be agreed from time to time between the registry manager and the Authority.

11.24 Registry manager reports to specific participants
The registry manager must deliver the reports specified in clauses 11.25 to 11.27 in the manner specified in those clauses.

11.25 Reports to the clearing manager, system operator or reconciliation manager

(4) If the request is received by the time specified in this clause, the registry manager must provide the report by 1000 hours on the 1st business day of the calendar month following the calendar month in which the request was made, or if the request for the report specifies a later date, by the later date.
(5) The person who requested the report may vary any of the details set out in the request, by giving notification to the registry manager of the relevant details in writing by no later than 5 business days before the last day of the month before the 1st month for which the person requests the variation.
(6) The registry manager must comply with a request made in accordance with subclause (5) by 1000 hours on the 1st business day of the calendar month following the calendar month in which the request was made.

11.26 Reports to the reconciliation manager
By 1600 hours on the 4th business day of each calendar month, in respect of the immediately preceding consumption period, and by 1600 hours on the 13th business day of each calendar month in respect of the immediately preceding 14 consumption periods, the registry manager must deliver the following reports to the reconciliation manager:
(a) a report identifying the number of ICP days per NSP, differentiated by half-hour metering type or non half-hour metering type (for the purpose of this clause, half-hour metering type on the registry must be reported as half hour, and all other
metering types must be reported as non half hour attributable to each trader for those NSPs that are recorded on the registry as consuming electricity at any time during, as the case may be, that consumption period or any of those consumption periods:

(b) a report detailing the loss factor values for each loss category code recorded by the registry in respect of all trading periods:

c) a report detailing the balancing area to which each NSP belongs recorded by the registry in respect of all trading periods (including any changes during that month):

(d) a report detailing the half hour ICP identifiers and the NSPs to which they are assigned for each individual trader (including any changes during that month):

e) a report that sets out every switch made under clauses 2, 9 or 14 of Schedule 11.3, the effect of which is that a trader has commenced trading at an NSP or a trader has ceased trading at an NSP.

11.27 Reports to the market administrator

By 1600 hours on the 1st business day of each calendar month, the registry manager must deliver to the market administrator a report summarising the number of events that have not been notified to the registry manager, of which it is aware, within the timeframes specified in this Part.

11.28 Access to registry

(1) A participant may apply to the Authority to have access to information held by the registry.

(2) If the Authority grants a participant’s application, the Authority must specify terms and conditions under which the Authority grants access to the information is to be provided.

(2A) The participant must comply with the terms and conditions specified by the Authority under subclause (2).

(3) The registry manager must provide to the participant access to information held by the registry in accordance with those terms and conditions.

(4) If the Authority grants a participant has been provided access to information in the registry, and the participant requests a report, the registry manager must provide a copy of the report to the participant within 4 hours of receiving the request.

(5) In determining whether the registry manager has provided a copy of the report has been provided within the time specified in subclause (4), no account is to be taken of any period during which the registry is not required to be available under clause 11.20.

11.29 Registry information change

If a change to registry information is provided in accordance with clause 11.7, the registry manager must, within 1 business day of receiving the information, advise affected participants of the change.

Schedule 11.1
1 ICP identifiers

... (2) The ICP identifier must be used by a participant in all communications with the registry manager to identify—
Provision of ICP information to the registry manager

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

…

(2) The distributor must provide the information specified in subclauses (1)(a) to (1)(o) to the registry manager as soon as practicable after the ICP identifier for the ICP to which the information relates is created, and before electricity is traded at the ICP.

(2A) The distributor must provide the information specified in subclause (1)(p) to the registry manager no later than 10 business days after the date on which the ICP is initially energised.

(3) The distributor must provide the following information to the registry manager no later than 10 business days after the trading of electricity at the ICP commences:

…

(8) A distributor may provide the registry manager with global positioning system coordinates for each ICP on the distributor’s network.

(9) If a distributor provides the global positioning system coordinates of an ICP to the registry manager under subclause (8), it must provide the coordinates—

…

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 notify the registry manager of the change.

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

…

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

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

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 notify the registry manager of the change.

…
11 Correction of errors in the registry

(1) By 0900 hours on the 1st business day of each reconciliation period, the registry manager must provide to each participant who is required to submit submission information, the following:

…

22 Updating loss factors for loss category codes

…

(8) The registry manager must publish an updated schedule of all loss category codes and the loss factors for each loss category code no later than 1 business day after being notified of a change.

24 Balancing area information

…

(4) The reconciliation manager must notify the registry manager of changes to balancing areas within 1 business day after receiving the notification.

(5) The registry manager must publish an updated schedule of the mapping between NSPs and balancing areas within 1 business day after receiving the notification.

…

30 Reconciliation manager to advise registry manager

(1) The reconciliation manager must—

(a) advise the registry manager of any new or deleted NSP identifier no later than 1 business day after being notified of its creation or decommissioning; and

(b) advise the registry manager of any changes to supporting NSP information provided by a distributor in accordance with clause 26(4) no later than 1 business day after receiving the notification.

(2) The registry manager must publish an updated schedule of all NSP identifiers and supporting information within 1 business day of any change being notified to it in accordance with subclause (1).

Schedule 11.2

9 The registry manager must remove any information that has been notified to the registry manager under clause 7 of Schedule 11.1 relating to an ICP for which a transfer has been notified under this Schedule, if the information was to have come into effect after the date on which the market administrator authorises the change of information on the registry under this Schedule.

Schedule 11.3

2 Gaining trader advises registry manager of standard switch request

(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch no later than 2 business days after the arrangement with the customer or embedded generator comes into effect.

(2) The gaining trader must include in its advice to the registry manager—

…
3 Losing trader response to standard switch request
No later than 3 business days after receiving notification of a switch request from the registry manager under clause 22(a), the losing trader must,—
(a) either—
   (i) acknowledge the switch request by providing the following information to the registry manager:

4 Event dates
(1) The losing trader must establish event dates so that—
   (a) no event date is more than 10 business days after the date of notification from the registry manager in accordance with clause 22(a); and

5 Losing trader must provide final information
If the losing trader has provided information under clause 3(a)(i) rather than under clause 3(a)(ii), no later than 5 business days after the event date, the losing trader must complete the switch by providing final information to the registry manager, including—

6 Traders must use same reading
   ...
   (3) No later than 5 business days after receiving final information from the registry manager under clause 22(d),—
   ...

9 Gaining trader informs registry manager of switch request
(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch request no later than 2 business days after the arrangement with the customer or embedded generator comes into effect.
(2) The gaining trader must include in its advice to the registry manager—

10 Losing trader response to switch move request
(1) After receiving notification of a switch request from the registry manager under clause 22(a), the trader that is recorded on the registry as being responsible for the ICP (the “losing trader”) must, no later than 5 business days after receiving the notification,—
   (a) if the losing trader accepts the event date proposed by the gaining trader, complete the switch by providing to the registry manager—
      (i) [Revoked]
      (ia) confirmation of the event date; and
      (ib) a valid switch response code approved by the Authority; and
      (ii) final information in accordance with clause 11; or
   (b) if the losing trader does not accept the event date proposed by the gaining trader, acknowledge the switch request to the registry manager and determine a different event date that—
      ...

(2) If the losing trader determines a different event date under subclause (1)(b), the losing trader must also complete the switch by providing to the registry manager the
information described in subclause (1)(a), but in that case the event date is the event date determined by the losing trader.

11 Losing trader must provide final information
The losing trader must provide final information to the registry manager for the purposes of clause 10(1)(a)(ii), including—

12 Gaining trader may change switch event meter reading
(2B) No later than 5 business days after receiving final information from the registry manager under clause 22(d),—

14 Gaining trader informs registry manager of switch request
(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch request no later than 3 business days after the arrangement with the customer or embedded generator comes into effect.
(2) The gaining trader must include in its advice to the registry manager—
   (a) a proposed event date; and
   (b) that the switch type is HH.
(3) Unless subclause (4) applies, the proposed event date must be a date that is after the date on which the gaining trader advises the registry manager.
(4) The proposed event date may be a date that is before the date on which the gaining trader advises the registry manager, if—
   (a) the proposed event date is in the same month as the date on which the gaining trader advises the registry manager; or
   (b) the proposed event date is no more than 90 days before the date on which the gaining trader advises the registry manager, and the losing trader and gaining trader agree on the proposed event date.

15 Losing trader provides information
No later than 3 business days after the losing trader receives information from the registry manager in accordance with clause 22(a), the losing trader must—
   (a) provide the registry manager with a valid switch response code approved by the Authority; or
   (b) request that the switch be withdrawn in accordance with clause 17.

16 Gaining trader obligations
(1) The gaining trader must complete the switch by advising the registry manager of the event date no later than 3 business days after receiving a valid switch response code from the registry manager under clause 22(c).

18 Withdrawing a switch request
If a trader requests the withdrawal of a switch under clause 17, the following provisions apply:
(a) the Authority must determine the valid codes for withdrawing a switch request ("withdrawal advisory codes"): 
(b) the Authority must publish the withdrawal advisory codes: 
(c) for each ICP, the trader withdrawing the switch request must provide the registry manager with the following information: 
   (i) the participant identifier of the trader; and 
   (ii) the withdrawal advisory code published by the Authority in accordance with paragraph (b): 
(d) no later than 5 business days after receiving a notification from the registry manager in accordance with clause 22(b), the trader receiving the withdrawal must notify the registry manager that the switch withdrawal request is accepted or rejected. A switch withdrawal request must not become effective until accepted by the trader who received the withdrawal: 
(e) on receipt of a rejection notification from the registry manager in accordance with paragraph (d), a trader may re-submit a switch withdrawal request for an ICP in accordance with paragraph (c). All switch withdrawal requests must be resolved no later than 10 business days after the date of the initial switch withdrawal request: 
(f) if a trader requests that a switch request be withdrawn and the resolution of that switch withdrawal request results in the switch proceeding, no later than 2 business days after receipt of notification from the registry manager in accordance with clause 22(b), the losing trader must comply with clauses 3, 5, 10 and 11 (whichever is appropriate) and the gaining trader must comply with clause 16.

22 Registry manager notifications
The registry manager must provide notifications to participants required by this Schedule as follows:
(a) on receipt of information about a switch request in accordance with clauses 2, 9 and 14, the registry manager must notify the losing trader of the information received: 
(b) on receipt of information about a withdrawal request in accordance with clauses 18(c) and (d), the registry manager must notify the other relevant trader of the information received: 
(c) on receipt of information about a switch acknowledgement in accordance with clauses 3(a) and 15, the registry manager must notify the gaining trader of the information received: 
(d) on receipt of information about a switch completion in accordance with clauses 3(a)(ii), 5, 10 and 16, the registry manager must notify the gaining trader, the losing trader, the metering equipment provider, and the relevant distributor of the information received.

Schedule 11.4
1 Metering equipment provider receives notification for ICP identifier
(1) Within 10 business days of being advised by the registry manager under clause 11.18A, a gaining metering equipment provider,— 
   (a) must, if it intends to accept responsibility for each metering installation for the ICP— 
      (i) enter into an arrangement with the trader; and
(ii) advise the registry manager in the prescribed form that it accepts responsibility for each metering installation for the ICP and of the proposed date on which the metering equipment provider will assume responsibility for each metering installation for the ICP; or

(b) may, if it intends to decline responsibility for each metering installation for the ICP, advise the registry manager in the prescribed form that it declines to accept responsibility for each metering installation for the ICP.

(2) The registry manager must, within 1 business day of a metering equipment provider advising under subclause (1)(b) that it declines to accept responsibility for each metering installation for the ICP, advise the trader of the declination.

(3) The registry manager must, within 1 business day of a gaining metering equipment provider advising of acceptance under subclause (1)(a), advise the following participants for the ICP of the acceptance and proposed date on which the gaining metering equipment provider will assume responsibility for each metering installation for the ICP:

...
(2) A metering equipment provider must, as soon as reasonably practicable but not later than 5 business days after it obtains the information under subclause (1), compare the information obtained with its own records.

(3) If the metering equipment provider finds a discrepancy between the information obtained under subclause (1) and its own records, the metering equipment provider must, within 5 business days of becoming aware of the discrepancy,—  
(a) correct its records that are in error; and  
(b) advise the registry manager of any necessary changes to the registry metering records.

7 Metering equipment provider to provide registry metering records to registry manager  
(1) A metering equipment provider must, if required under this Part, provide to the registry manager the information indicated in Table 1 as being "Required", in the prescribed form, for each metering installation for which it is responsible.

(2) Despite anything to the contrary in this Code (except clause 11.2) the metering equipment provider must—  
(a) provide the information set out in Table 1 indicated as being required for interim certified metering installations to the registry manager for all category 1 metering installations for which it is responsible; and

Schedule 11.5  
3 Authority may require distributor and registry manager to provide information  
(1) The Authority may, by notice in writing to a distributor on whose network a defaulting trader trades electricity, require the distributor to provide to the Authority the information about the defaulting trader's customers specified in the notice (if the distributor holds the information), within the period specified in the notice.

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

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

(4) The registry manager must provide the information requested by the Authority under subclause (3) within the time specified by the Authority.

4B Authority may direct registry manager to take certain actions  
(1) If the Authority gives notice to a trader under clause 4, the Authority may, by notice to the registry manager, direct the registry manager not to—  
(a) complete the switch of any ICP to the defaulting trader; or  
(b) accept a request from the defaulting trader to withdraw a switch under clauses 17 and 18 of Schedule 11.3.

(2) If the Authority gives notice under subclause (1), the registry manager must not—  
(a) complete the switch of any ICP to the defaulting trader; or
(b) accept a request from the defaulting trader to withdraw a switch under clauses 17 and 18 of Schedule 11.3.

5 Authority may assign contracts and ICPs

(2) The Authority may—
(a) exercise its right under a contract under which a customer purchases electricity from the defaulting trader to assign the rights and obligations of the defaulting trader under the contract to a recipient trader in accordance with the contract; and
(b) assign an ICP to a recipient trader and direct the registry manager to amend the record in the registry so that the recipient trader is recorded as being responsible for the ICP; and

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

7 Registry manager may complete switch without required information
If the Authority gives notice under clause 2, the registry manager may complete the switch of any ICP for which the defaulting trader is recorded in the registry as being responsible even if the defaulting trader has not complied with its obligations under Schedule 11.3.

Part 15

15.1 Contents of this Part
This Part provides for the following:

(g) obligations of the reconciliation manager to pass the information to reconciliation participants, the registry manager and the Authority:

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 held by the registry for the relevant consumption period at the time the reconciliation participant assembles the submission information.

15.20B Reconciliation manager loss adjusts and summarises dispatchable load information

(3) The Authority may direct the reconciliation manager to apply specified values for loss factors for each loss category for a reconciliation period for which the registry manager does not provide the reconciliation manager with the loss factors for each loss category in accordance with clause 11.26(b).

Schedule 15.2
21 Audit trails
(2) The audit trail must—
(a) include details of information—
   (i) provided to and received from the registry manager;

Schedule 15.4
2 Overview of key reconciliation events
Each reconciliation participant must comply with the timing requirements summarised below:

<table>
<thead>
<tr>
<th>Timing</th>
<th>Reconciliation process</th>
<th>Revisions cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commencement of the 1st day of the reconciliation period</td>
<td>Beginning of reconciliation period.</td>
<td>Beginning of reconciliation period.</td>
</tr>
<tr>
<td>By 1600 hours on the 4th business day of the reconciliation period</td>
<td>The registry manager must make available, and the reconciliation manager must procure, ICP days, loss factor and balancing area and half hour ICP identifiers information, in accordance with clauses 11.24 to 11.27. Each reconciliation participant must submit to the reconciliation manager submission information, retailer information and NSP information, in accordance with clauses 15.4 to 15.12.</td>
<td></td>
</tr>
<tr>
<td>By 1600 hours on the 7th business day of the reconciliation period</td>
<td>The reconciliation manager must complete a reconciliation of the submission information provided by participants and the grid owner in accordance with this Schedule, and must make reconciliation information available to each reconciliation participant who submitted the submission information to which it relates, and the clearing manager for settlement.</td>
<td></td>
</tr>
<tr>
<td>From the 8th business day</td>
<td>Each reconciliation</td>
<td></td>
</tr>
</tbody>
</table>
### Timing

<table>
<thead>
<tr>
<th>of the reconciliation period</th>
<th>Reconciliation process</th>
<th>Revisions cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Participant</strong> must seek to resolve all inaccuracies and disputes concerning the reconciliation information.</td>
<td>Each <strong>reconciliation participant</strong> must submit to the <strong>reconciliation manager</strong> revised <strong>submission information, retailer information and NSP information</strong> in accordance with clauses 15.4 to 15.12, 15.27, and 15.28, and clause 10 of Schedule 15.3. The <strong>registry manager</strong> must make available and the <strong>reconciliation manager</strong> must procure revised <strong>ICP days, loss factor, balancing area and half hour ICP identifiers</strong> information, in accordance with clauses 11.24 to 11.27, and clause 10 of Schedule 15.3.</td>
<td><strong>By 1600 hours on the 13th business day of the reconciliation period</strong></td>
</tr>
</tbody>
</table>

| By 1200 hours on the last business day of the reconciliation period | **The reconciliation manager** must distribute revised **reconciliation information** to the entitled **reconciliation participants** and the **clearing manager**, in accordance with clause 28 of this Schedule. | **By 1200 hours on the last business day of the reconciliation period** |

---

### 6 ICP days information

...  

(2) The **registry manager** must deliver to the **reconciliation manager**, in accordance with clauses 11.24 to 11.27, the number of **half hour** and non **half hour ICP days** per **NSP** each **retailer** and **direct purchaser** (excluding **direct consumers**) is responsible for during each **consumption period**.

---

### 7 ICP scaling factor calculation

(1) The **reconciliation manager** must, using the **retailer** and **direct purchaser** reported **ICP days** and **registry** reported **ICP days**, calculate **ICP day** scaling factors separately in respect of non **half hour** and **half hour** metered **ICPs** according to the following formula:

\[
\text{ICPSF} = \frac{\text{ICPD}_{\text{REG}}}{\text{ICPD}_{\text{RTL}}} \\
\text{where} \\
\text{ICPSF} \quad \text{is the ICP scaling factor}
\]
ICPD\textsubscript{REG} is the number of ICP days for that retailer per balancing area as reported by the registry manager.

ICPD\textsubscript{RTL} is the number of ICP days for that retailer for that balancing area as reported by each retailer.

provided that if—

(a) the ICP scaling factor is calculated to be less than 1, it must, for the purposes of this clause, be deemed to be 1; and

(b) the ICP scaling factor is calculated to be greater than 1, it must not exceed a figure nominated and published from time to time by the Authority.

... 

(3) If the ICP days value reported by a retailer or a direct purchaser in respect of a balancing area is 0, or if data is not supplied, but in each case the corresponding ICP days value from the registry manager is not 0, the reconciliation manager must add to that retailer’s submission information for that consumption period an amount (designated SIICPD-ADD) that is equal to—

(a) 25 kWh per ICP day, in respect of non half hour ICPs; and

(b) 40 kWh per trading period per ICP day, in respect of half hour ICPs.

(4) The relevant number of ICP days is the value reported by the registry manager.

15 Loss factors

(1) The Authority may, from time to time, direct the reconciliation manager to apply certain values for loss factors for each loss category for a reconciliation period for which the registry manager does not, for whatever reason, provide the reconciliation manager with the loss factors for each loss category in accordance with clause 11.26(b).
Part 1

**asset** means equipment or plant that is connected to or forms part of the grid and, in the case of Part 8, includes equipment or plant that is intended to become connected to the grid and equipment or plant of an **embedded generator**

**associated equipment**, for the purposes of the definition of **distribution network** and Part 6, means any equipment that is used, or designed or intended for use, in connection with any works or **consumer installation**, if such use is for **construction**, maintenance, or safety purposes and not for purposes that relate directly to the generation, conversion, transformation, conveyance, or use of **electricity**

**back up protection system** means a protection system—
(a) that disconnects faulted assets from the grid because a **main protection system** or a **circuit breaker** has failed to electrically disconnect a faulted asset from the grid in the allocated time; and
(b) that may electrically disconnect non-faulted assets as well as a faulted asset

**balancing area** means, in relation to any particular ICP,—
(a) the embedded network; or
(b) that part of the relevant **local network** owned by 1 network owner—having 1 or more NSPs, to which that ICP is electrically connected from time to time under normal circumstances

**benchmark agreement** means the agreement for the connection to and/or use of the grid, that is incorporated by reference in this Code under clause 12.34

**black start** means an **ancillary service** required to enable a generating unit isolated from the grid to be livened as defined in the Electricity (Safety) Regulations 2010, and electrically connected to the grid

**circuit breaker failure protection system** means a protection system that—
(a) operates because a circuit breaker has failed to electrically disconnect a faulted asset from the grid in the allocated time; and
(b) may electrically disconnect non-faulted assets from the grid as well as a faulted asset

**commissioning** means, for the purposes of Part 10, to verify the correct operation of an asset, or a point of connection, or of metering equipment installed in a metering installation

**connect**, in relation to distributed generation, means to be electrically connected to a distribution network or to a consumer installation that is electrically connected to a distribution network, and connected, connection, and connecting have corresponding meanings

**connection and operation standards**, in relation to a distributor or distributed generation,—
(a) means requirements, as amended from time to time by the distributor, that—
(i) are set out in written policies and standards of the distributor; and
(ii) relate to the connection of connecting distributed generation to a distribution network or to a consumer installation that is connected to a distribution network, including requirements relating to the planning, design, construction, testing, inspection, and operation of assets distributed generation that are, or are proposed to be, connected; and
(iii) are made publicly available in accordance with clause 6.3; and
(iv) reflect, or are consistent with, reasonable and prudent operating practice; and
(b) includes the following, as amended from time to time by the distributor:
(i) the distributor's congestion management policy, as referred to in clause 6.3(2)(d); and
(ii) the distributor's emergency response policies; and
(iii) the distributor's safety standards

collection location means a substation or other location at which lines, equipment and plant owned or managed by a designated transmission customer that are directly related to a point of connection, and that are used for the consumption, conveyance, or generation of electricity, are directly connected to the grid

consumer installation, for the purposes of the definitions of associated equipment, connect, and Part 6, means—
(a) all fittings that are part of a system for conveying electricity from a consumer’s point of supply to any point from which electricity conveyed through that system may be consumed; and
(b) includes any fittings that are used, or designed or intended for use, by any person in or in connection with relation to the generation of electricity—
(i) for that person’s use and not for supply to any other person; or
(ii) so that electricity can be injected into a distribution network; but
c) does not include any appliance that uses, or is designed or intended to use, electricity, whether or not it also uses, or is designed or intended to use, any other form of energy

decommissioning means—
(a) for the purposes of Part 10, the permanent physical removal from service of an asset or a point of connection or the permanent removal of a metering installation for associated 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 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
**de-energisation** means the operation of any isolator, circuit breaker, or switch, or the removal of any fuse or link, so that no electricity can flow through a point of connection on a network, and de-energise and de-energised have corresponding meanings.

**disconnected** means, in relation to a grid injection point, grid exit point or point of connection, that there is no load or generation at, or connected to, the grid injection point, grid exit point or point of connection in the modelling system.

**distributed generation** means generating plant that is, or is proposed to be, connected to a distribution network or to a consumer installation that is connected to a distribution network, or proposed to be connected, but does not include—

(a) generating plant that is connected to a distribution network and operated by a distributor for the purpose of maintaining or restoring the provision of electricity to part or all of the distributor’s distribution network—

(i) as a result of a planned distribution network outage; or

(ii) as a result of an unplanned distribution network outage; or

(iii) during a period when the distribution network capacity would otherwise be exceeded on part or all of the distribution network; or

(b) generating plant that is only momentarily synchronised with the distribution network for the purpose of switching operations to start or stop the generating plant.

**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 connection with, the generation of electricity for that person’s use and not for supply to any other person), but does not include any electrical appliance.

**electrically connecting** means connecting, or permitting the connection of, a new point of connection to a network, for the purposes of an activity regulated under Parts 11 or 15, and electrically connect and electrically connected have corresponding meanings.

**electrically connect** means to operate a device so that electricity is able to flow, including through a point of connection, and electrically connected, electrically connecting, electrical connection, and similar phrases have corresponding meanings.

**electrically disconnect** means to operate a device so that electricity is unable to flow, including through a point of connection, and electrically disconnected, electrically disconnecting, electrical disconnection, and similar phrases have corresponding meanings.

**embedded generating station** means 1 or more generating units that are directly connected to a local network or an embedded network and that injects into a local network or an embedded network at a single point of injection.

**embedded network** means a system of lines, substations, and other works, used primarily for the conveyance of electricity, that—

(a) is connected, indirectly connected to the grid only through 1 or more other networks; and
(b) has 1 or more ICP identifiers recorded in the registry as being electrically connected to it

electrical connected means the operation of an isolator, circuit breaker, or switch, or the placing of a fuse or link, so that electricity can flow through a point of connection on a network, and

(a) energise and energised have corresponding meanings; and
(b) [Revoked]

existing assets means transmission assets and non-transmission projects that have been commissioned before, and are in operation at the time of, application of a net benefits tests set out in Part 12. To avoid doubt, an investment in the expansion of generating capacity of an existing generating unit is not an existing asset or part of an existing asset, unless the additional generating capacity associated with the investment has been commissioned before, and is in operation at the time of, the application of the relevant net benefits test.

export congestion means a situation in which a distribution network is unable to accept electricity exported from a distributed generation connection because the injection of an additional unit of electricity into the distribution network would—

(a) directly cause a component in the network to operate beyond the component's rated maximum capacity; or
(b) give rise to an unacceptably high level of voltage at the point of connection between the distribution network and the distributed generation.

generating station means 1 or more generating units that are directly connected to the grid or to a local network and that inject into the grid or a local network (as the case may be) at a single point of injection.

generating unit load means the active and reactive power supplied or injected via connections between the generating unit's output terminals and its generating unit circuit breaker.

generator means 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.

grid means the system of transmission lines, substations and other works, including the HVDC link used to connect grid injection points and grid exit points to convey electricity throughout the North Island and the South Island of New Zealand.

grid interface means the assets used to make a connection to the grid (as the case may be), including associated protection, control and communication systems. The term includes the interface between assets forming part of the grid.

high spring washer price situation means a situation in a trading period in which—

(a) 1 or more transmission security constraints bind; and
(b) the software used by the pricing manager to calculate provisional prices, interim prices, and final prices (or used by the system operator to determine, under clause 13.134(4), whether a high spring washer price situation still exists) calculates a price for electricity at any grid injection point or grid exit point, excluding grid
injection points and grid exit points that are electrically disconnected, that is equal to or greater than the product of the high spring washer price trigger ratio and the highest unconstrained cleared offer price in that trading period.

**high voltage terminal** means the connection point at which the higher voltage side of a grid owner's transformer connects to the grid.

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

(a) a point of connection at which a customer installation is connected to a network other than the grid;

(b) a point of connection between a network and an embedded network;

(c) a point of connection between a network and shared unmetered load.

**incremental costs, for the purpose of Part 6**, means the reasonable costs that an efficient distributor would incur in providing electricity distribution services with connection services to distributed generation, less the costs that the efficient distributor would incur if it did not provide those connection services.

**input connection contract** means the fixed term input connection assets contracts between Transpower and each of the following: Tuaropaki Power Company Limited, Carter Holt Harvey Limited, Contact Energy Limited, Empower Limited, and Mighty River Power Limited.

**interruptible load** means a form of instantaneous reserve comprised of energy being consumed that is able to be electrically disconnected to balance the injection supply and the offtake of electricity following a drop in system frequency to a specified level below 50 Hz.

**interruption**, for the purposes of Part 12, means an interruption in the conveyance of electricity between assets owned or operated by a designated transmission customer and the grid assets owned by Transpower at a point of connection, other than an interruption by reason of Transpower being directed to electrically disconnect and de-energise a point of connection by the Authority or the Rulings Panel under the Act or this Code or by the clearing manager or any other person authorised to do so by this Code.

**main protection system** means a protection system that detects 1 or more types of faults and electrically disconnects a faulted asset from the grid with the minimum of disruption to the grid and non-faulted assets.

**notified planned outages** means planned outages of assets forming part of or connected to the grid or local network that have been planned by the asset owners concerned and have been notified to the system operator in accordance with Technical Code D of Schedule 8.3.

**notional embedding contracts** means contracts entered into before 1 April 2008 between Transpower and its customers, under which a customer's generation assets are treated as if they were physically connected to load in lieu of their existing connection to the grid.

**outage constraint** means any grid injection point or grid exit point that has no load or generation connected to it in the modelling systems disconnected, as notified by the system operator in accordance with clauses 15.15 to 15.17.
**ratio compensation** means a multiplier, used to convert **raw meter data** into **volume information**, that is developed from—
(a) the **connected** ratio of **measuring transformers**; and
(b) the number of **metering** elements; and
(c) the resolution of the **meter**

**reasonable and prudent operating practice**, in relation to **distributed generation**, includes—
(a) the industry operating standards; and
(b) measures to avoid the injection of **electricity** from **distributed generation** that—
(i) exceeds the **distribution network capacity** at the point of injection; or
(ii) results in a significant adverse effect on voltage levels; or
(iii) results in a significant adverse effect on the quality and reliability of **electricity** conveyed to other users of the **distribution network**; and
(c) the use or proposed use of reasonable and prudent measures to enable the **connection** of **distributed generation**

**reference point** means,—
(a) for the North Island,—
(i) the Haywards 220 kV bus to which the HVDC Pole 2 or Pole 3 **injection** or **offtake** is **electrically connected**; or
(ii) if there is no Pole 2 or Pole 3 **injection** or **offtake** **electrically connected** to a Haywards 220kV bus, the first indexed Haywards 220 kV **node**;
(b) for the South Island,—
(i) the Benmore 220 kV bus to which the HVDC Pole 2 or Pole 3 **injection** or **offtake** is **electrically connected**; or
(ii) if there is no Pole 2 or Pole 3 **injection** or **offtake** **electrically connected** to a Benmore 220kV bus, the first indexed Benmore 220 kV **node**

**shunt asset**, for the purposes of Part 12, means a shunt **connected asset** that is an **interconnection asset**

**single credible contingency event** means an individual credible contingency event comprising any of the following:
(a) a single transmission circuit interruption:
(b) the failure or removal from operational service of a single **generating unit**:
(c) an **HVDC link** single pole interruption:
(d) the failure or removal from service of a single bus section:
(e) a single inter-connecting transformer interruption:
(f) the failure or removal from service of a single shunt **connected reactive component**

**synchronised** means the condition whereby a synchronous machine is **electrically connected** to a **network** and the electrical angular velocity of the machine corresponds with the **network** frequency and **synchronise, de-synchronise, synchronising, synchronism and synchronisation** have corresponding meanings. Asynchronous **intermittent generating stations** must be treated as being **synchronised** for the purposes of subpart 2 of Part 8
system test means a test conducted on an asset, with the asset electrically connected to the grid, to assess the interaction of the asset with the grid.

temporary energisation means the temporary energisation of a point of connection for the purposes of carrying out, at that point of connection,—
(a) the activities or processes necessary for, or as part of, the certification of a metering installation; or
(b) the maintenance, repair, testing, or commissioning of a metering installation.

transmission agreement means an agreement for connection and/or use of the grid under subpart 2 of Part 12 (including, if relevant, an agreement for investment in the grid).

wind generating station means 1 or more generating units that are connected to the grid or to a local network and that inject into the grid or a local network (as the case may be) at a single point of injection, and for which wind is the primary power source.

1.5A Application of Code to distributors
Except in Parts 6, 9, and 12A, nothing in this Code applies to a distributor in respect of its distribution activities that are not conducted on a network that is—
(a) directly connected to the grid; or
(b) indirectly connected to the grid through 1 or more other networks.

Part 2

2.8 Transfer of requests
(1) This clause applies if—
(a) a notice is sent to a participant under clause 2.4(b); and
(b) the information to which the request relates—
   (i) is not held by the participant but is believed by the person dealing with the notice to be held by another participant; or
   (ii) is believed by the person dealing with the notice to be more closely related to the activities of another participant.

(2) The participant to which the notice was sent must promptly, and in any case not later than 10 working days after the day on which the notice is received, transfer the notice to the other participant, and inform the Authority accordingly.

Part 3

3.17 Market operation service provider must arrange audit of software
(1) Unless otherwise agreed by the Authority in writing, each market operation service provider must arrange and pay for a suitably qualified independent person approved by the Authority to carry out—
(a) before any **software** is first used by the **market operation service provider** in connection with relation to this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**, an **audit** of all **software** and **software specifications** to be used by the **market operation service provider**; and

(b) an annual **audit** of all **software** used by the **market operation service provider**, within 1 month after 1 March in each year; and

(c) an **audit** of any changes to the **software** or the **software specification**, before it is used by the **market operation service provider**.

(2) A **market operation service provider** must ensure that the person carrying out an **audit** under subclause (1) provides a report to the **Authority** as to—

(a) the performance (including likely future performance) of all of the **software** in accordance with the relevant **software specification**; and

(b) any other matters that the **Authority** requires.

**Part 6**

6.1 **Contents of this Part**

This Part specifies—

(a) a framework to enable the **connection** and continued **connection** of distributed generation if consistent with connection and operation standards; and

(b) in Schedule 6.1, processes (including time frames) under which distributed generators may—

(i) **connect** distributed generation; or

(ii) continue an existing **connection** of distributed generation if the **connection** contract for the distributed generation—

(A) is in force and the distributed generator wishes to extend the term of the **connection** contract; or

(B) has expired; or

(iii) continue an existing **connection** of distributed generation that is **connected** without a **connection** contract if the regulated terms do not apply; or

(iv) change the **nameplate capacity** or fuel type of connected distributed generation; and

(c) in Schedule 6.2, the regulated terms that apply to the **connection** of distributed generation in the absence of contractually agreed terms; and

(d) in Schedule 6.3, a default dispute resolution process for disputes related to this Part; and

(e) in Schedule 6.4, the pricing principles to be applied for the purposes of this Part; and

(f) in Schedule 6.5, prescribed maximum fees.

6.2 **Purpose**

(1) The purpose of this Part is to enable the **connection** and continued **connection** of distributed generation to be connected to a **distribution network** or to a **consumer installation** that is connected to a **distribution network**, if being **connected** is consistent with connection and operation standards.
6.2A Application of Part to distributors in respect of embedded networks

Nothing in this Part applies to—
(a) a distributor in respect of the distributor's ownership or operation of an embedded network that conveys less than 5 GWh of electricity per annum; or
(b) a distributed generator when the distributed generator wishes to connect or has distributed generation connected to such an embedded network.

6.2B Application of Part to distributors in respect of systems of lines not directly or indirectly connected to the grid

Nothing in this Part applies to—
(a) a distributor in respect of the distributor's ownership or operation of a system of lines that is used for providing line function services only to the distributor; or
(b) a distributor in respect of the distributor's ownership or operation of a system of lines—
   (i) that conveys less than 5 GWh of electricity per annum; and
   (ii) that is not—
      (A) directly connected to the grid; or
      (B) indirectly connected to the grid through 1 or more other networks; or
(c) a distributed generator when the distributed generator wishes to connect or has distributed generation connected to a system of lines described in paragraph (b).

6.3 Distributors must make information publicly available

(1) The purpose of this clause is to require each distributor to make certain information publicly available to enable the approval of distributed generation under Schedule 6.1.

(2) Each distributor must make publicly available, free of charge, from its office and Internet site,—
(a) forms for applications under Schedule 6.1; and
(b) the distributor's connection and operation standards; and
(c) a copy of the regulated terms, together with an explanation of how the regulated terms will apply if—
   (i) approval is granted under Schedule 6.1; and
   (ii) the distributor and the distributed generator do not enter into a connection contract; and
(d) a statement of the policies, rules, or conditions under which distributed generation will be, or may be, curtailed or interrupted from time to time in order to ensure that the distributor's other connection and operation standards are met; and
(da) a list of all locations on its distribution network that the distributor—
   (i) knows to be subject to export congestion; or
   (ii) expects to become subject to export congestion within the next 12 months; and
(e) a list of any fees that the distributor charges under Schedule 6.1, which must not exceed the relevant maximum fees prescribed in Schedule 6.5; and
(f) a list of the makes and models of inverters that the distributor has approved for connection to its distribution network; and
(g) the distributor’s contact information for any enquiries relating to the connection of distributed generation to its distribution network.

(3) The application forms referred to in subclause (2)(a) must specify the information, including any supporting documents, that must be provided with an application under Schedule 6.1.

6.4 Process for obtaining approval

(1) Schedule 6.1 applies if a distributed generator wishes to—

(a) connect distributed generation, whether on the regulated terms or on other terms; or

(b) continue an existing connection of distributed generation if the connection contract for the distributed generation—

(i) is in force and the distributed generator wishes to extend the term of the connection contract; or

(ii) has expired; or

(c) continue an existing connection of distributed generation that is connected without a connection contract if the regulated terms do not apply; or

(d) change the nameplate capacity or fuel type of connected distributed generation.

(2) A distributor must approve an application submitted under Schedule 6.1 if the application complies with the requirements of that Schedule.

(3) Except as provided in clause 6.4A, a distributor cannot contract out of the provisions of Schedule 6.1 with a distributed generator.

6.4A Distributor and distributed generator may agree to simpler process for existing connection

A distributor and a distributed generator may agree a simpler process for the continued connection of distributed generation to the distributor's distribution network than the relevant process set out in Schedule 6.1 if—

(a) a connection contract for the distributed generation—

(i) is in force and the distributed generator wishes to extend the term of the connection contract; or

(ii) has expired; or

(b) the distributed generation is connected without a connection contract; or

(c) there is a change in the nameplate capacity or fuel type of the distributed generation.

6.5 Connection contract

If a distributor and a distributed generator enter into a connection contract for the connection of distributed generation,—

(a) their rights and obligations in respect of the connection of the distributed generation are governed by that contract, and accordingly the regulated terms do not apply; and

(b) a breach of the terms of that contract is not a breach of this Code.
6.6 Connection on regulated terms

(1) Schedule 6.2 sets out the regulated terms for the connection of distributed generation.

(2) The regulated terms apply in the following circumstances:

(a) if a distributor and a distributed generator do not enter into a connection contract by the expiry of the period for negotiating a connection contract under clauses 9 or 24 of Schedule 6.1;

(b) in accordance with clause 9G of Schedule 6.1.

(3) If the regulated terms apply,—

(a) the parties' rights and obligations in respect of the connection of the distributed generation are governed by the regulated terms; and

(b) a breach of the regulated terms is not a breach of contract.

(4) Despite this clause, a distributor and a distributed generator may at any time, by agreement, enter into a connection contract that will apply instead of the regulated terms.

6.7 Extra terms

(1) The parties' rights and obligations in respect of a connection on the regulated terms are also governed by any other terms and conditions that—

(a) were made publicly available under clause 6.3(2)(d) in a statement of the terms and conditions that would apply to distributed generation if there is congestion on the distribution network; or

(b) cover any other incidental matters (for example, invoicing procedures) if—

(i) the matters are not covered by the regulated terms; and

(ii) the other matters are reasonable terms and conditions that either were proposed by the distributor during the 30 business day negotiation period as part of a connection contract or are terms that would be implied by law if the connection was under a connection contract; and

(iii) the other terms and conditions do not contradict any of the regulated terms.

(2) In this Part, if the parties have agreed to change all or any part of 1 or more of the regulated terms as part of a binding contract, the resulting contract is, in total, a connection contract on terms that apply instead of the regulated terms for the purposes of this Part.

6.8 Dispute resolution

(1) Subject to subclause (2), Schedule 6.3 applies to a dispute between a distributed generator that is a participant and a distributor arising from any one of the following—

(a) an allegation that a party has breached any of the regulated terms that apply under clause 6.6(2); and

(aa) an allegation that conditions specified by the distributor under clause 18 of Schedule 6.1 are not reasonably required; and

(ab) an allegation that a party has not attempted to negotiate in good faith under clause 6 or clause 21 of Schedule 6.1; and

(b) an allegation that a party has breached any of the other provisions of this Part.

(2) However, Schedule 6.3 does not apply to disputes between a distributed generator and a distributor—
(a) arising from an allegation that a party has breached any of the terms of a connection contract; or
(b) arising from an allegation that a party has breached any of the extra terms referred to in clause 6.7(1); or
(c) that the distributed generator and the distributor have agreed should be determined by any other agreed method (for example, under any dispute resolution scheme under section 95 of the Act).

6.13 This Part does not apply to earlier connections
This Part does not apply in relation to, or affect, any distributed generation that was connected under a contract entered into before 30 August 2007, except for the purpose of renewing or extending the term of the contract.

Schedule 6.1

1A Contents of this Schedule
This Schedule specifies the procedures for processing applications from distributed generators for the connection or continued connection of distributed generation.

1B Distributed generator must apply
Subject to clause 6.4A and clause 1D, a distributed generator that owns or operates distributed generation must apply to a distributor if it wishes to—
(a) connect the distributed generation to the distributor's distribution network; or
(b) continue an existing connection of the distributed generation to the distributor's distribution network if a connection contract for the distributed generation—

(i) is in force and the distributed generator wishes to extend the term of the connection contract; or
(ii) has expired; or
(c) continue an existing connection of the distributed generation to the distributor's distribution network that is connected without a connection contract if the regulated terms do not apply; or
(d) change the nameplate capacity or fuel type of the distributed generation connected to the distributor's distribution network.

2 Applications under this Part of this Schedule

... (3) The information may include the following:
(a) the full name and address of the distributed generator and the contact details of a person that the distributor may contact regarding the distributed generation:
(aa) whether the application is to—

(i) connect distributed generation; or
(ii) continue an existing connection of distributed generation that is connected in accordance with a connection contract if the connection contract—
(A) is in force and the distributed generator wishes to extend the term of the connection contract; or
(B) has expired; or
(iii) continue an existing connection of distributed generation that is connected without a connection contract; or
(iv) change the nameplate capacity or fuel type of connected distributed generation:
(b) evidence of the nameplate capacity that the distributed generation will have, or other suitable evidence that the distributed generation is or will only be capable of generating electricity at a rate of 10 kW or less:
(ba) if the application is to change the nameplate capacity or fuel type of connected distributed generation—
(i) the nameplate capacity that the distributed generation will have after the change; and
(ii) the aggregate nameplate capacity that all distributed generation that is connected at the point of connection at which the distributed generation is connected will have after the change; and
(iii) the fuel type that the distributed generation will have after the change:
(c) details of the fuel type of the distributed generation (for example, solar, wind, or liquid fuel):
(d) a brief description of the physical location at the address at which the distributed generation is or will be connected:
(da) if the application is to connect distributed generation, when the distributed generation is expected to be connected:
(e) technical specifications of the distributed generation and associated equipment, including the following:
(i) technical specifications of equipment that allows the distributed generation to be electrically disconnected from the distribution network on loss of mains voltage:
(ii) manufacturer's rating of equipment:
(iii) number of phases:
(iv) proposed or current point of connection to the distribution network (for example, the ICP identifier and street address):
(v) details of either or both of any inverter and battery storage:
(vi) details of any load at the proposed or current point of connection:
(vii) details of the voltage (for example, 230/400 or 11 kV) when electrically connected:
(f) information showing how the distributed generation complies with the distributor's connection and operation standards:
(g) any additional information or documents that are reasonably required by the distributor.
...

5 Distributed generator must give notice of intention to proceed
(1) If a distributor advises a distributed generator that its application is approved, the distributed generator must give written notice to the distributor confirming whether or not the distributed generator intends to proceed to negotiate a connection.
contract under clause 6 and, if so, confirming the details of the distributed generation to which the application relates.

(2) The distributed generator must give the notice within 10 business days after the distributor gives notice of approval, or such later date as is agreed by the distributor and the distributed generator.

(3) The distributor's duties under Part 6 of this Code arising from the application no longer apply if the distributed generator fails to give notice to the distributor within the time limit specified in subclause (2).

(4) Subclause (3) does not prevent the distributed generator from making a new application under Part 6 of this Code.

6 30 business days to negotiate connection contract if distributed generator notifies intention to proceed

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

(2) The distributor and the distributed generator may, by agreement, extend the time specified in subclause (1) for negotiating a connection contract.

8 Connection of distributed generation if connection contract negotiated

(1) This clause applies if a distributor and a distributed generator whose application under this Part of this Schedule is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation in accordance with the contract as soon as practicable.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply—

(a) as soon as practicable, if the previous connection contract has expired; or
(b) no later than the expiry of the previous connection contract, if the contract is in force.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply as soon as practicable.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply as soon as practicable.
9 Connection of distributed generation on regulated terms if connection contract not negotiated

(1) This clause applies if a distributor and a distributed generator whose application under this Part of this Schedule is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation on the regulated terms as soon as practicable after the expiry of the period.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the regulated terms apply to the distributed generator’s existing connection as follows:

   (a) if the previous connection contract has expired, the regulated terms apply from the day after the date on which the period for negotiating a connection contract under this Part of this Schedule expires:

   (b) if the previous connection contract is still in force, the regulated terms apply from the day after the date on which the contract expired.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the regulated terms apply from the day after the date that the period for negotiating a connection contract under this Part of this Schedule expires.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the regulated terms apply from the day after the date that the period for negotiating a connection contract under this Part of this Schedule expires.

9B Application for distributed generation of 10 kW or less in total in specified circumstances

(1) A distributed generator’s application to a distributor must specify which of the following circumstances applies:

   (a) the distributed generator wishes to connect distributed generation:

   (b) the distributed generator wishes to continue an existing connection of distributed generation that is connected in accordance with a connection contract that—

      (i) is in force and the distributed generator wishes to extend the term of the connection contract; or

      (ii) has expired:

   (c) the distributed generator wishes to continue an existing connection of distributed generation that is connected without a connection contract:

   (d) the distributed generator wishes to change the nameplate capacity or fuel type of connected distributed generation.

(2) An application must include the following:

   (a) the name, contact, and address details of the distributed generator and, if applicable, the distributed generator’s agent:
(b) a brief description of the physical location at the address at which the distributed generation is or will be connected;
(c) any application fee specified by the distributor in accordance with clause 6.3(2)(c);
(d) details of the make and model of the inverter;
(e) confirmation as to whether the inverter—
(i) is included on the distributor’s list of approved inverters made publicly available under clause 6.3(2)(f); or
(ii) conforms with the protection settings specified in the distributor’s connection and operation standards;
(f) if the inverter is not included on the distributor’s list of approved inverters, a copy of the AS 4777.2 Declaration of Conformity certificate for the inverter;
(g) details of—
(i) the nameplate capacity of the distributed generation; and
(ii) the fuel type of the distributed generation (for example, solar, wind, or liquid fuel).

(3) The distributed generator must also give the distributor the following information as soon as it is available, but no later than 10 business days after the approval of the application:
(a) a copy of the Certificate of Compliance issued under the Electricity (Safety) Regulations 2010 that relates to the distributed generation;
(b) the ICP identifier of the ICP at which the distributed generation is connected or is proposed to be connected, if one exists.

(4) A distributor must, no later than 2 business days after receiving an application from a distributed generator, acknowledge receipt of the application.

9C Distributor may inspect distributed generation
(1) A distributor may inspect distributed generation that is connected or is proposed to be connected to its distribution network for the purpose of—
(a) verifying that the distributed generation meets, or continues to meet, the requirements specified in clause 1D; or
(b) verifying the information contained in an application made under this Part of this Schedule.

(2) If a distributor wishes to inspect distributed generation, the distributor must give the distributed generator at least 2 business days’ notice of the time and date on which the inspection will take place.

(3) Following receipt of a notice, the distributed generator must—
(a) pay the fee specified by the distributor in accordance with clause 6.3(2)(e) for the inspection (if any); and
(b) provide or arrange for the distributor to have reasonable access to the distributed generation.

9D Export congestion
(1) This clause applies if a distributed generator applies to a distributor under this Part of this Schedule to connect distributed generation or continue an existing connection of distributed generation to a location on the distributor’s distribution network that is included in the list published in accordance with clause 6.3(2)(da).

(2) The distributor may advise the distributed generator that the distributed generation may be subject to export congestion as set out in the distributor’s congestion management policy.
(3) If a distributor has advised a distributed generator under subclause (2), the distributor must take reasonable steps to work with the distributed generator to assess whether solutions exist to mitigate the export congestion.

9E Non-compliance or incomplete information

(1) This clause applies if a distributor considers that an application made to it by a distributed generator under this Part of this Schedule has 1 or more of the following deficiencies:
   (a) the distributed generation to which the application relates does not meet the requirements specified in clause 1D;
   (b) the distributed generation to which the application relates is not as described in the information given under clause 9B(2):
      (c) the distributed generator has not complied with clause 9B(2).

(2) If this clause applies, the distributor must advise the distributed generator of the deficiency or deficiencies.

(3) If the distributed generator is advised of a deficiency or deficiencies, it must remedy each deficiency to the satisfaction of the distributor no later than 10 business days after being advised of the deficiency.

(4) If the distributed generator is required to remedy a deficiency it must pay the relevant fee specified by the distributor in accordance with clause 6.3(2)(e).

(5) If the distributed generator does not remedy each deficiency of which it is advised within the time frame specified in subclause (3)—
   (a) if the distributed generation to which the application relates is electrically connected to the distributor's distribution network at the time of being advised under subclause (2), the distributor may, by notice to the distributed generator, require the distributed generator to—
      (i) electrically disconnect disconnect the distributed generation within a reasonable time frame specified by the distributor (if applicable); or
      (ii) keep the distributed generation electrically disconnected until each deficiency is remedied to the distributor's satisfaction; or
   (b) if the distributed generation is not connected to the distributor’s distribution network at the time of being advised under subclause (2), the distributor may, by notice to the distributed generator, prohibit the distributed generator from connecting the distributed generation to the distributor's distribution network until each deficiency is remedied to the distributor’s satisfaction.

(6) The distributor must approve the connection or reconnection of the distributed generation (as the case may be) as soon as is reasonable in the circumstances if—
   (a) the distributed generator disconnects its distributed generation complies with a notice given under subclause (5)(a) (if applicable); and
   (b) the distributed generator remedies each deficiency advised under subclause (2)—
      (i) to the satisfaction of the distributor; and
      (ii) no later than 12 months after the date of the notice given under subclause (5) or such later date as is agreed by the distributor and the distributed generator.

(7) If the distributor approves the connection or reconnection of distributed generation, it must give a notice of final approval to the distributed generator under clause 9F.
9G Regulated terms apply
(1) If a distributor gives a notice of final approval to a distributed generator under clause 9F, the regulated terms apply.
(2) Despite subclause (1), and in accordance with clause 6.6(4), the distributor and distributed generator may at any time enter into a connection contract on terms that apply instead of the regulated terms.

9H When distributed generator may connect to distribution network
(1) A distributed generator that has submitted an application to a distributor under clause 1D may connect the distributed generation to which the application relates to the distributor's distribution network if the distributed generator receives a notice of final approval under clause 9F(1), or is deemed to have received a notice of final approval under clause 9F(3).
(2) Despite subclause (1) a distributor may prohibit a distributed generator from connecting if—
   (a) the distributor has advised the distributed generator of a deficiency under clause 9E(2) and the deficiency has not been remedied in accordance with clause 9E(3); or
   (b) the distributor gave notice that it wished to inspect the distributed generation under clause 9C(2), but the distributed generator has not provided or arranged for the distributor to have reasonable access to the distributed generation under clause 9C(3)(b).

11 Distributed generator must make initial application and give information
(1) [Revoked]
(2) A distributed generator must apply to a distributor ("initial application") by—
   (a) using the application form provided by the distributor that is publicly available under clause 6.3(2)(a); and
   (b) providing any information in respect of the distributed generation to which the application relates that is—
      (i) referred to in subclause (3); and
      (ii) specified by the distributor under clause 6.3(3) as being required to be provided with the application; and
   (c) paying the application fee (if any) specified by the distributor in accordance with clause 6.3(2)(e).
(3) The information may include the following:
   (a) the full name and address of the distributed generator and the contact details of a person whom the distributor may contact regarding the distributed generation;
      (aa) whether the application is to—
         (i) connect distributed generation; or
         (ii) continue an existing connection of distributed generation that is connected in accordance with a connection contract if the connection contract—
            (A) is in force and the distributed generator wishes to extend the term of the connection contract; or
            (B) has expired; or
         (iii) continue an existing connection of distributed generation that is connected without a connection contract; or
         (iv) change the nameplate capacity or fuel type of connected distributed generation:
(b) evidence of the nameplate capacity that the distributed generation will have:
(ba) if the application is to change the nameplate capacity or fuel type of connected distributed generation.—
   (i) the nameplate capacity that the distributed generation will have after the change; and
   (ii) the aggregate nameplate capacity that all distributed generation that is connected at the point of connection at which the distributed generation is connected will have after the change; and
   (iii) the fuel type that the distributed generation will have after the change:
(c) details of the fuel type of the distributed generation (for example, solar, wind, or liquid fuel):
(d) a brief description of the physical location at the address at which the distributed generation is or will be connected:
(da) if the application is to connect distributed generation, when the distributed generation is expected to be connected:
(e) technical specifications of the distributed generation and associated equipment, including the following:
   (i) technical specifications of equipment that allows the distributed generation to be electrically disconnected from the distribution network on loss of mains voltage:
   (ii) manufacturer's rating of equipment:
   (iii) number of phases:
   (iv) proposed or current point of connection to the distribution network (for example, the ICP identifier and street address):
   (v) details of either or both of any inverter and battery storage:
   (vi) details of any load at the proposed or current point of connection:
   (vii) details of the voltage (for example, 230/400415 V or 11 kV) when electrically connected:
(f) information showing how the distributed generation complies with the distributor's connection and operation standards:
(g) the maximum active power injected (MW max):
(h) the reactive power requirements (MVArs) (if any):
(i) resistance and reactance details of the distributed generation:
(j) fault level contribution (kA):
(k) method of voltage control:
(l) single line diagram of proposed connection:
(m) means of synchronising with, synchronisation and electrically connecting to, and electrically disconnecting disconnecting to from, the distribution network, including the type and ratings of the proposed circuit breaker:
(n) details of compliance with frequency and voltage support requirements as specified in this Code (if applicable):
(o) proposed periods and amounts of electricity injections into, and offtakes from, the distribution network (if known):
(p) any other information that is required by the system operator:
(q) any additional information or documents that are reasonably required by the distributor.
(4) [Revoked]

(5) The distributor must, within 5 business days of receiving an initial application, give written notice to the applicant advising whether or not the application is complete.

12 Distributor must give information to distributed generator
A distributor must give a distributed generator that makes an initial application the following within 30 business days of receiving the completed initial application:
(a) information about the capacity of the distribution network, including both the design capacity (including fault levels) and actual operating levels:
(b) information about the extent to which connection and operation of the distributed generation may result in a breach of the relevant standards for safety, voltage, power quality, and reliability of electricity conveyed to points of connection on the distribution network:
(c) information about any measures or conditions (including modifications to the design and operation of the distribution network or to the operation of the distributed generation) that may be necessary to address the matters referred to in paragraphs (a) and (b):
(d) the approximate costs of any distribution network related measures or conditions identified under paragraph (c) and an estimate of time constraints or restrictions that may delay the connecting of the distributed generation:
(e) information about any further detailed investigative studies that the distributor reasonably considers are necessary to identify any potential adverse effects the distributed generation may have on the system, together with an indication of—
(i) whether the distributor agrees to the distributed generator, or a suitably qualified agent of the distributed generator, undertaking those studies; or
(ii) if not, whether the distributor could undertake those studies and, if so, the reasonable estimated cost of the studies that the distributed generator would be charged:
(f) information about any obligations to other parties that may be imposed on the distributor and that could affect the distributed generation (for example, obligations to Transpower, in respect of other networks, or under this Code):
(g) any additional information or documents that the distributor considers would assist the distributed generator's application:
(h) information about the extent to which planned and unplanned outages may adversely affect the operation of the distributed generation.

16 Notice to third parties
A distributor that receives a final application must give written notice to the following persons no later than 10 business days after receiving the final application:
(a) all persons that have made an initial application relating to a particular part of the distribution network that the distributor considers would be affected by the approval of the final application; and
(b) all distributed generators that have distributed generation with a nameplate capacity of 10 kW or more in total connected on the regulated terms to the particular part of the distribution network that the distributor considers would be affected by the approval of the final application.
Distributed generator must give notice of intention to proceed

1. If a distributor advises a distributed generator that the distributed generator's final application is approved, the distributed generator must give written notice to the distributor confirming whether or not the distributed generator intends to proceed to negotiate a connection contract under clause 21(1) and, if so, confirming—
   (a) the details of the distributed generation; and
   (b) that the distributed generator accepts all of the conditions (or other measures) that have been specified by the distributor under clause 18.

2. The distributed generator must give the notice no later than 30 business days after the day on which the distributor gives notice of approval under clause 18, or such later date as is agreed by the distributor and the distributed generator.

3. If the distributed generator is a participant and does not accept 1 or more of the conditions specified by the distributor under clause 18(2) (if any), but intends to proceed to negotiate a connection contract under clause 21(1), the distributed generator must—
   (a) give notice of the dispute in accordance with clause 2 of Schedule 6.3 within 30 business days after the day on which the distributor gives notice of approval under clause 18; and
   (b) give a notice under subclause (1) within 30 business days after the dispute is resolved.

4. The distributor's duties under Part 6 of this Code arising from the application no longer apply if the distributed generator fails to give notice to the distributor of an intention to proceed to negotiate a connection contract under clause 21(1) within the time limits specified in this clause.

5. Subclause (4) does not prevent the distributed generator from making a new application under Part 6 of this Code.

30 business days to negotiate connection contract if distributed generator notifies intention to proceed

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

2. The distributor and the distributed generator may, by agreement, extend the time specified in subclause (1) for negotiating a connection contract.

Connection of distributed generation if connection contract negotiated

1. This clause applies if a distributor and a distributed generator whose final application is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

2. If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation in accordance with the contract as soon as practicable.
(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply—
(a) as soon as practicable, if the previous connection contract has expired; or
(b) no later than the expiry of the previous connection contract, if the contract is in force.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply as soon as practicable.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply as soon as practicable.

24 Connection of distributed generation on regulated terms if connection contract not negotiated

(1) This clause applies if a distributor and a distributed generator whose final application is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation on the regulated terms as soon as practicable after the later of the following:
(a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
(b) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the regulated terms apply to the distributed generator's existing connection from the later of the following:
(a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
(b) the expiry of the existing connection contract:
(c) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the regulated terms apply from the later of the following:
(a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
(b) the date on which the **distributed generator** has fully complied with any conditions (or other measures) that were specified by the **distributor** under clause 18 as conditions of the **connection**.

(5) If the application is to change the **nameplate capacity** or fuel type of connected **distributed generation** under clause 1B(d), the **regulated terms** apply from the later of the following:

(a) the expiry of the period for negotiating a **connection** contract under this Part of this Schedule:

(b) the date on which the **distributed generator** has fully complied with any conditions (or other measures) that were specified by the **distributor** under clause 18 as conditions of the **connection**.

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25 **Confidentiality of information provided**

(1) All information given with, or relating to, an application made under this Schedule to a **distributor** must be kept confidential by the **distributor** except as agreed otherwise by the person that gave the information.

(1A) A **distributor** may require a **distributed generator** to keep confidential information that—

(a) is given to the **distributed generator** by the **distributor** for the purpose of an application under this Schedule; and

(b) the **distributor** reasonably identifies as being confidential.

(1B) A **distributor** is excused from processing an application made by a **distributed generator** under this Schedule if the **distributed generator** does not agree to comply with a requirement to keep information confidential imposed under subclause (1A).

(2) Despite subclause (1), the **distributor**—

(a) may, in response to an application under this Schedule, disclose to the applicant that another **distributed generator** has made an application under this Schedule (without identifying who the other **distributed generator** is); and

(b) may, in the case of an application under Part 1 of this Schedule, generally indicate the location or proposed location of the **distributed generation** that is the subject of the other application; and

(c) may, in the case of an application under Part 2 of this Schedule, disclose the **nameplate capacity** and proposed location of the **distributed generation** that is the subject of the other application.

(3) The obligation to keep information confidential set out in subclause (1) includes—

(a) an obligation not to use the information for any purpose other than considering the application under this Schedule and enabling the **connection** or continued **connection** of the **distributed generation**; and

(b) an obligation to destroy the information as soon as is reasonably practicable after the later of—

(i) the date on which the information is no longer required for the purposes in paragraph (a); and

(ii) 60 months after receiving the information.
Schedule 6.2

1 Contents of this Schedule
This Schedule sets out the regulated terms that apply to a distributor and a distributed generator in respect of distributed generation that is connected in accordance with clause 6.6 of Part 6 of this Code and Schedule 6.1.

3 General obligations
(1) The distributor and the distributed generator must perform all obligations under these regulated terms in accordance with connection and operation standards (where applicable).
(2) The distributor and the distributed generator must each construct, interconnect, operate, test, and maintain their respective equipment in accordance with—
   (a) these regulated terms; and
   (b) connection and operation standards (where applicable); and
   (c) this Code.
(3) The distributed generator must, subject to subclause (2), construct, interconnect, operate, test, and maintain its distributed generation in accordance with—
   (a) reasonable and prudent operating practice; and
   (b) the applicable manufacturer's instructions and recommendations.
(4) The distributor and distributed generator must each be fully responsible for the respective facilities they own or operate.
(5) The distributor and distributed generator must each ensure that their respective facilities adequately protect each other's equipment, personnel, and other persons and their property, from damage and injury.
(6) The distributed generator must comply with any conditions specified by the distributor under clause 18 of Schedule 6.1 (or, to the extent that those conditions were the subject of a dispute under clause 20(3) of that Schedule, or of negotiation during the period for negotiation of the connection contract, the conditions or other measures as finally resolved or negotiated).

4 Installation of meters and access to metering information
(1) [Revoked]
(2) The distributed generator must give the distributor, at the distributor's request, the interval data and cumulative data recorded by the metering installations at the point of connection at which the distributed generation is connected or is proposed to be connected.
(3) The distributed generator must provide reactive metering if—
   (a) the meter for the distributed generation is part of a category 2 metering installation, or a higher category of metering installation; and
   (b) the distributed generator is required to do so by the distributor.
(4) The distributor's requirements in respect of metering measurement and accuracy must be the same as set out in Part 10 of this Code.
5 Right of distributor to access distributed generator's premises
(1) The distributed generator must provide the distributor, or a person appointed by the distributor, with safe and unobstructed access onto the distributed generator's premises at all reasonable times—

... (e) for the purposes of electrically reconnecting or electrically disconnecting the distributed generation; and

(f) for any other purpose relevant to either or both of—
   (i) the distributor connecting distributed generation in accordance with connection and operation standards; and
   (ii) maintaining the integrity of the distribution network.
...

10 General obligation relating to interruptions
The distributor must make reasonable endeavours to ensure that the connection of the distributed generation is not interrupted.

11 Circumstances allowing distributor to temporarily electrically disconnect distributed generation
Despite clause 10, the distributor may interrupt the connection service, or curtail either the operation or output of the generation, or both, and may temporarily electrically disconnect the distributed generation in any of the following cases:
(a) in accordance with the distributor's congestion management policy:
(b) if reasonably necessary for planned maintenance, construction, and repairs on the distribution network:
(c) for the purpose of protecting, or preventing danger or damage to, persons or property:
(d) if the distributed generator fails to allow the distributor access as required by clause 5:
(e) [Revoked]
(f) in accordance with clause 13 (adverse operating effects):
(g) if the distributed generator fails to comply with the distributor’s—
   (i) connection and operation standards; or
   (ii) safety requirements.

12 Obligations if distributed generation temporarily electrically disconnected by distributor
(1) The distributor must make reasonable endeavours to—
   (a) advise the distributed generator before an interruption under clause 11; and
   (b) co-ordinate with the distributed generator to minimise the impact of the interruption.
(2) The distributor and the distributed generator must co-operate to restore the distribution network and the distributed generation to a normal operating state as soon as is reasonably practicable following temporary disconnection of the distributed generation being temporarily electrically disconnected.
(3) In the case of a forced outage, the distributor must, subject to the need to restore the distribution network, make reasonable endeavours to—
(a) restore service to the distributed generator; and
(b) advise the distributed generator of the expected duration of the outage.

13 Adverse operating effects
(1) The distributor must advise the distributed generator as soon as is reasonably practicable if it reasonably considers that operation of the distributed generation may—
(a) adversely affect the service provided to other distribution network customers; or
(b) cause damage to the distribution network or other facilities; or
(c) present a hazard to a person.
(2) If, after receiving that advice, the distributed generator fails to remedy the adverse operating effect within a reasonable time, the distributor may electrically disconnect the distributed generation by giving reasonable notice (or without notice when reasonably necessary in the event of an emergency or hazardous situation).

14 Interruptions by distributed generator
(1) This clause applies to any connected distributed generation above 10 kW in total.
(2) The distributed generator must advise the distributor of any planned outages and must make reasonable endeavours to advise the distributor of an event that affects distribution network operations.
(3) The distributed generator must make reasonable endeavours to advise the distributor of the interruption and to co-ordinate with the distributor to minimise the impact of the interruption.

15 Disconnecting distributed generation
Permanent disconnections
(1) Despite clause 10, the distributor may permanently disconnect distributed generation in the following circumstances:
(a) on receipt of a request from a distributed generator;
(b) without notice, if a distributed generator has been temporarily electrically disconnected under clause 11(g) and—
(i) the distributed generator fails to remedy the non-compliance within a reasonable period of time; and
(ii) there is an ongoing risk to persons or property;
(c) without notice, if the trader that is recorded in the registry as being responsible for the ICP to which the distributed generation is connected to the distribution network has de-energised the ICP and advised the registry that the ICP has a status of "inactive" with the reason of "de-energised – ready for decommissioning";
(d) on at least 10 business days' notice of intention to disconnect, if—
(i) the distributed generator has not injected electricity into the distribution network at any time in the preceding 12 months; and
(ii) the distributor has not been notified by the distributed generator of reasons for the non-injection; and
(iii) the distributor has reasonable grounds for believing that the distributed...
generator has ceased to operate the distributed generation.

(2) [Revoked]

(3) If a distributor disconnects distributed generation under subclause (1) and the point of connection is to be decommissioned, the distributor must—
   (a) remove all electrical conductors between the distributed generation and the distributor's lines;
   (b) advise the distributed generator within 2 business days of the work referred to in subclause (a) having been completed.

(3) If the point of connection is to be disestablished in its entirety, a permanent disconnection must be performed by means of isolation of generation by removal of all electrical connections to distributor's lines. The distributor must advise the distributed generator within 2 business days of the work having been completed.

(4) [Revoked]

(5) [Revoked]

15A Distributed generator must construct distributed generation within 18 months of approval

(1) This clause applies if the distributor approves the distributed generator's application to connect distributed generation under Part 1, Part 1A, or Part 2 of Schedule 6.1.

(2) The regulated terms cease to apply if the distributed generator does not construct the distributed generation within—
   (a) 18 months from the date on which approval was granted; or
   (b) such later date as is agreed by the distributor and distributed generator.

(3) The distributed generator must reapply under Schedule 6.1 if—
   (a) the regulated terms no longer apply in accordance with subclause (1); and
   (b) the distributed generator wishes to connect distributed generation to the distributor's distribution network.

Schedule 6.3

4 Application of pricing principles to disputes

(1) The Authority and the Rulings Panel must apply the pricing principles set out in Schedule 6.4 to determine any connection charges payable.

(2) Subclause (1) applies if—
   (a) there is a dispute under Part 6 of this Code; and
   (b) in the opinion of the Authority or the Rulings Panel it is necessary or desirable to apply subclause (1) in order to resolve the dispute.

Schedule 6.4

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of distributed generation must not exceed the incremental costs of providing connection
connection services to the distributed generation. To avoid doubt, incremental cost is net of transmission and distribution costs that an efficient distributor would be able to avoid as a result of the connection of the distributed generation:

(b) costs that cannot be calculated (e.g., avoidable costs) must be estimated with reference to reasonable estimates of how the distributor's capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the distributor as a result of the distributed generation being connected to the distribution network were, and deducting the costs that would have been incurred had the generation not been connected. In this case, if the costs differ from the costs charged to the distributed generator, the distributor must advise the distributed generator and recover or refund those costs after they are incurred (unless the distributor and the distributed generator agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant asset replacement or upgrade, the connection charge attributable to the distributed generator's actions or proposals is payable by the distributed generator before the distributor has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the distributor is not obliged to incur those costs until that payment has been received:

(e) if incremental costs are negative, the distributed generator is deemed to be providing network support services to the distributor, and may invoice the distributor for this service and, in that case, the distributed generator must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine maintenance, the connection charge attributable to the distributed generator's actions or proposals may take the form of a periodic charge:

(g) [Revoked]

(h) after the connection of the distributed generation, the distributor may review the connection charges payable by a distributed generator not more than once in any 12-month period. Following a review, the distributor must advise the distributed generator in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) if multiple distributed generators are sharing an investment, the portion of costs payable by any 1 distributed generator—

(i) must be calculated so that the charges paid or payable by each distributed generator take into account the relative expected peak of each distributed generator's injected generation; and
(ii) may also have regard to the percentage of assets that will be used by each distributed generator, the percentage of distribution network capacity used by each distributed generator, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the distribution network:

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the distributor must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating distributed generation, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a distributed generator has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other distributed generators, the distributor must refund to the distributed generator all connection charges paid to the distributor under paragraph (i) by other distributed generators in respect of that investment:

(l) if there are multiple prior distributed generators, a refund to each distributed generator referred to in paragraph (k) must be provided in accordance with the expected peak of that distributed generator's injected generation over a period of time agreed between the distributed generator and the distributor. The refund—

(i) must take into account the relative expected peak of each distributed generator's injected generation; and

(ii) may also have regard to the percentage of assets that will be used by each distributed generator, the percentage of distribution network capacity used by each distributed generator, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the distribution network:

(m) no refund of previous payments from the distributed generator referred to in paragraph (k) is required after a period of 36 months from the initial connection of that distributed generator:

Non-firm connection service

(n) to avoid doubt, nothing in Part 6 of this Code creates any distribution network capacity or property rights in any part of the distribution network unless these are specifically contracted for. Distributors must maintain connection and lines services to distributed generators in accordance with their connection and operation standards.
Part 7

7.3 Functions of the system operator in relation to security of supply and emergency management

(1) The system operator must—
   (a) prepare and publish a security of supply forecasting and information policy that includes a requirement that the system operator—
      (i) prepare and publish at least annually a security of supply assessment that contains detailed supply and demand forecasts for at least 5 years, which assists interested parties to assess whether the energy security of supply standard and the capacity security of supply standard set out in subclause (2) are likely to be met; and
      (ii) consult with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by a security of supply assessment prepared under subparagraph (i) before publishing such an assessment; and
      (iii) prepare and publish information that assists interested parties to monitor how hydro and thermal generating capacity, transmission assets, primary fuel, and ancillary services are being utilised to manage risks of shortage, including extended dry periods; and
      (iv) publish, in connection with relation to the information published under subparagraphs (i) and (iii), sufficient details of the modelling data, assumptions, and methodologies that the system operator has used to prepare that information as to allow interested parties to recreate that information (but without publishing information that is confidential to any participant); and
   …

Part 8

8.15 System operator to prepare and review system security forecast

(1) Every 2 years, the system operator must prepare, publish, and provide to the Authority a system security forecast.

(1A) The system security forecast must—
   (a) identify risks to the system operator’s ability to meet the principal performance obligations over the ensuing period of not less than 36 months, and indicate how those risks can be managed; and
   (b) take into account the capabilities of the grid and connected assets based on information known to, and able to be disclosed by, the system operator.

(2) The date by which the system operator must publish the system security forecast and provide it to the Authority in each year in which the system operator is required to do so, is the date established for that purpose under rule 15 of section II of part C of the rules.

(3) The system operator must review the most recent system security forecast prepared in accordance with subclause (1) at 6 monthly intervals until a new forecast or update is prepared. If, in the reasonable opinion of the system operator, a change has been made to
the power system that would materially affect the most recent forecast or update, the system operator must amend the system security forecast, publish it and provide it to the Authority.

8.19 Contributions to frequency support in under-frequency events

(1) Subject to subclause (3), each generator must at all times ensure that, while electrically connected, its assets, other than any excluded generating stations, contribute to supporting frequency by remaining synchronised, ensuring that each of its generating units can and does, at a minimum, sustain pre-event output—

(a) at all times when the frequency is above 47.5 Hertz; and
(b) for at least 120 seconds when the frequency is 47.5 Hertz; and
(c) for at least 20 seconds when the frequency is 47.3 Hertz; and
(d) for at least 5 seconds when the frequency is 47.1 Hertz; and
(e) for at least 0.1 seconds when the frequency is 47.0 Hertz; and
(f) at any frequencies between those specified in paragraphs (b) to (e) for times derived by linear interpolation.

(2) If the inherent characteristics and design of a generator's generating unit are such that it is reasonably able to operate beyond the above requirements, the generator must declare such capabilities in accordance with clause 2(5) of Technical Code A of Schedule 8.3.

(3) Each South Island generator must ensure that each of its assets, other than excluded generating units, remains synchronised, and can and do, at a minimum, sustain pre-event output—

(a) at all times when the frequency is above 47 Hertz; and
(b) for 30 seconds if the frequency falls below 47 Hertz but not below 45 Hertz.

(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—

(a) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains above 48 Hertz; and
(b) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains below 48 Hertz and above 47 Hertz for 90 seconds; and
(c) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains above 45 Hertz for 35 seconds, unless the frequency in either island is less than 46.5 Hertz and the frequency is falling at a rate of 7 Hertz per second or greater; and
(d) subject to the level of transfer and the HVDC link 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.

(5) Each extended reserve provider must provide extended reserve in accordance with Schedule 8.3, Technical Code B.
8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19 and the provisions in Technical Code A of Schedule 8.3 relating to the obligations of asset owners in respect of frequency, an excluded generating station means a generating station that exports less than 30 MW to a local network or the grid, unless the Authority has issued a direction under clause 8.38 that the generating station must comply with clauses 8.17, 8.19, and the relevant provisions in Technical Code A of Schedule 8.3.

(2) Whether likely to be an excluded generation station or not, a generator who is planning to connect to the grid or a local network a generating unit with rated net maximum capacity equal to or greater than 1 MW must provide the system operator with written advice of its intention to connect together with other information relating to that generating unit in accordance with clause 8.25(4).

8.25 Other asset owner performance obligations and technical standards

(1) Each grid owner must ensure that the design and configuration of its assets (including its connections to other persons) and associated protection arrangements are consistent with the technical codes and, in the reasonable opinion of the system operator, with maintaining the system operator’s ability to comply with the principal performance obligations. In reaching this opinion, the system operator must have regard to the potential impact of the design or configuration of those assets or associated protection arrangements on its compliance with the principal performance obligations and achievement of the dispatch objective.

(2) Each grid owner and each connected asset owner must use reasonable endeavours to ensure that a generator who meets the following criteria provides the system operator with written advice of the existence of its generating unit and the generator’s name and address:

(a) the generator is directly connected to the grid owner's grid or directly or indirectly connected to the local network (as the case may be):

(b) the generator has a generating unit with a rated net maximum capacity equal to or greater than 1 MW.

(3) Each asset owner and each purchaser must provide communication facilities that comply with the technical codes or otherwise, as the system operator reasonably requires, which must assist the system operator in planning to comply, and complying, with its principal performance obligations and achieving the dispatch objective.

(4) Each asset owner and each purchaser must provide information that complies with the technical codes or otherwise as the system operator reasonably requests, to assist the system operator in planning to comply, and complying, with its principal performance obligations and achieving the dispatch objective.

(5) If the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with the principal performance obligations and achieving the dispatch objective, the system operator—

(a) may require that an embedded generator provide information regarding the intended output of each embedded generating station greater than 10 MW in capacity, that must be either—

(i) submitted as an offer in accordance with subpart 1 of Part 13; or
(ii) provided in a form and manner agreed between the system operator and the embedded generator; and

(b) the system operator must notify the embedded generator of its requirement at least 20 business days in advance of the requirement coming into effect.

(6) If the system operator reasonably considers it necessary to assist it in planning to comply, and complying, with the principal performance obligations and achieving the dispatch objective, the system operator may apply to the Authority to require an embedded generator to provide information regarding the intended output of a group of embedded generating stations that total greater than 10 MW in capacity and that are connected to the same grid exit point. If the Authority approves the system operator’s request, the information must be provided to the system operator by the relevant embedded generator in a form and manner determined by the Authority.

8.28 Responsibility for compliance

(1) Each asset owner must comply with the asset owner performance obligations and technical codes at all times and must satisfy the system operator, whenever requested by the system operator acting reasonably, that each of its assets or configuration of assets complies with the asset owner performance obligations and technical codes that apply to that asset or configuration of assets.

(2) If an asset owner receives notification under clause 8.27(3), it must co-operate with the system operator and use reasonable endeavours to restore compliance as soon as practicable.

(3) During a period of commissioning or testing of assets, the asset owner performance obligations and technical codes do not apply to the asset owner in respect of the assets, if—

(a) the obligations that do not apply to the asset owner are specified in the agreed commissioning plan or testing plan; and

(b) during the period of non-compliance the asset owner complies with a commissioning plan or testing plan (as appropriate) agreed with the system operator; and

(c) the period of non-compliance is no longer than the agreed commissioning plan or testing plan; and

(d) subject to subclause (4), if an asset owner during a period of non-compliance meets the requirements of paragraphs (a) to (c), neither the asset owner nor the system operator is liable under this Code in relation to the non-compliance, except that the asset owner is not relieved of liability in the case of a negligent act or omission by the asset owner.

(4) During any period of non-compliance, the non-compliant asset owner must pay the readily identifiable and quantifiable costs associated with its non-compliance, including the costs of the system operator purchasing additional ancillary services required as a consequence of its non-compliance.

Schedule 8.3, Technical Code A

2 General requirements

(1) Each asset owner must ensure that—
(a) its assets at grid exit points and at grid injection points, and, in the case of connected asset owners, the assets of any embedded generator connected to it, are identified and referred to by a system number; and
(b) its assets, both in the manner in which they are designed and operated, are capable of being operated, and operate, within the limits stated in the asset capability statement provided by the asset owner for that asset; and
(c) it meets any other reasonable requirements of the system operator, identified during planning studies, which are required for the system operator to plan to comply, or to comply, with its principal performance obligations.

(2) Each asset owner must provide the system operator with an asset capability statement, and any other information reasonably required by the system operator, to allow the system operator to assess compliance of its asset or any configuration of assets with the requirements of the asset owner performance obligations and technical codes at each of the following times:
(a) before the completion of planning for the construction of that asset or configuration of assets:
(b) at, or before, the completion of construction but before the commissioning of that asset or configuration of assets, except that the asset owner must put in place a commissioning plan in accordance with subclauses (6) to (8) to minimise the impact of commissioning tests on the system operator’s ability to comply with its principal performance obligations, and adhere to this plan during commissioning, unless otherwise agreed to by the system operator.

(3) On, or before, completion of commissioning of an asset or configuration of assets, the asset owner must obtain a final assessment in writing from the system operator that the asset or configuration of assets meets the requirements of the asset owner performance obligations and technical codes. This final assessment must be based on the information supplied by the asset owner and, if necessary, the result of system tests at commissioning.

(4) The system operator must give the assessment referred to in subclause (2)(b) within a reasonable time frame of the request and supply the asset owner with all information that supports its assessment. Any permission granted by the system operator to an asset owner to conduct commissioning of any asset or configuration of assets must permit connection of the asset (or configuration of assets) solely for the purposes of commissioning.

(5) Each asset owner must provide the system operator with an asset capability statement in the form from time to time published by the system operator for each asset that is proposed to be connected, or is connected, to, or forms part of the grid. The asset capability statement must—
(a) include all information reasonably requested by the system operator so as to allow the system operator to determine the limitations in the operation of the asset that the system operator needs to know for the safe and efficient operation of the grid; and
(b) include any modelling data for the planning studies, as reasonably requested by the system operator; and
(c) be updated and reissued to the **system operator** as information and design development progresses through the study, design, manufacture, testing and commissioning phases; and

(d) be complete and up to date before the commissioning of the asset; and

(e) be complete and up to date at all times while the asset is connected to, or forms part of, the grid.

(6) Each **asset owner** must provide a commissioning plan or test plan in accordance with subclauses (7) or (8) (as the case may be) in the following situations:

(a) when changes are made to assets that alter any of the following at the grid interface:
   (i) the single-line diagram;
   (ii) a protection system, other than a change to a protection system setting;
   (iii) a control system, including a change to a control system setting;
   (iv) any rating of assets;

(b) when assets are to be connected to, or are to form part of, the grid;

(c) if it is necessary for an asset owner to perform a system test or other test to ascertain or confirm asset capabilities, and if the commissioning or testing or connection of those assets may affect the system operator’s ability to plan to comply, or to comply with, its principal performance obligations. If an asset owner is unsure whether the commissioning or connection of an asset may impact on the system operator’s ability to plan to comply, and to comply, with the principal performance obligations it must contact the system operator for advice.

(7) The commissioning plan prepared by an asset owner and agreed by the system operator must—

(a) include a timetable containing the sequence of events necessary to connect the assets to the grid and conduct any proposed system test; and

(b) contain the protection and control settings to be applied before livening of the assets (where livening has the meaning given to it in the Electricity (Safety) Regulations 2010); and

(c) contain the procedures for commissioning the plant with minimum risk to personnel and plant and to the ability of the system operator to plan to comply and to comply with its principal performance obligations.

(8) If a test plan is required under subclause (6), it must be prepared by the asset owner in consultation with the system operator. The test plan must contain sufficient information to enable the system operator to plan to comply, and to comply, with the principal performance obligations.

(9) Once assessed by the system operator acting reasonably, the asset owner must follow the commissioning plan or test plan at all times, unless otherwise agreed with the system operator (such agreement must not be unreasonably withheld if compliance with the commissioning plan or testing plan is not practicable and non-compliance does not impact on the system operator's ability to comply with its principal performance obligations or on other asset owners).

3 Requirements for asset information
(1) In accordance with clause 8.25(4), the following information is required by the system operator to assist it to plan to comply, and to comply, with its principal performance obligations:

(a) sufficient information must be exchanged between the system operator and the asset owner to ensure that both fully understand the implications of any changes to the asset capability statement or of any proposed connection of the relevant assets to the grid or to the local network. This information must be exchanged in accordance with a timetable agreed to by the system operator and the asset owner:

(b) if reasonably requested by the system operator, the asset owner must provide sufficient information to the system operator to demonstrate the compliance of the asset owner's assets with the asset owner performance obligations and the technical codes.

(2) Information about an asset, supply or demand of other asset owners must only be disclosed by the system operator—

(a) as expressly provided for in this Code; or

(b) as reasonably required in a grid emergency or to ensure the security of the grid; or

(c) as required by law; or

(d) otherwise as may be agreed with the relevant asset owners.

(3) Each asset owner must provide the system operator with—

(a) all information reasonably requested by the system operator so as to ensure compliance with clause 8.25(4) and to enable the system operator to assess the grid interface; and

(b) details of protection systems, including settings, to ensure that the requirements of clause 8.25(4) are met.

(4) Each asset owner must ensure that all supporting information for the operational control of assets is kept up to date.

4 Requirements for grid and grid interface

(1) Each asset owner and grid owner must co-operate with the system operator to ensure that protection systems on both sides of a grid interface, which include main protection systems and back up protection systems, are co-ordinated so that a faulted asset is electrically disconnected by the main protection system first and the other assets are not prematurely electrically disconnected.

(2) A proposed grid interface, including the settings of any associated protection system, must be agreed between the relevant asset owner and the system operator before being implemented.

(3) Each asset owner must ensure that sufficient circuit breakers are provided for its assets so that each of its assets is able to be electrically disconnected totally from the grid whenever a fault occurs within the asset.

(4) Each asset owner must ensure that it provides protection systems for its assets that are connected to, or form part of, the grid. Each asset owner must also ensure that as a minimum requirement—

(a) such protection systems support the system operator in planning to comply, and complying, with the principal performance obligations and are designed,
commissioned and maintained, and settings are applied, to achieve the following performance in a reliable manner:

(i) \textbf{electrically disconnect} disconnect any faulted asset in minimum practical time (taking into account selectivity margins and industry best design practice) and minimum disruption to the operation of the grid or other assets:

(ii) be selective when operating, so that the minimum amount of assets are \textbf{electrically disconnected} disconnected:

(iii) as far as reasonably practicable, preserve power system stability; and

(b) it provides duplicated \textbf{main protection systems} for each of its \textbf{assets} at voltages of 220 kV a.c. or above, other than busbars; and

(c) it provides, for each of its 220 kV a.c. busbars—

(i) a single \textbf{main protection system} and a \textbf{back up protection system}; or

(ii) if the performance of its \textbf{back up protection system} does not meet the requirements of paragraph (a), a duplicated \textbf{main protection system}; and

(d) it provides duplicated \textbf{main protection systems} for each of its busbars at voltages above 220 kV a.c.; and

(e) it designs, tests and maintains its \textbf{main protection systems} at voltages of 220 kV a.c. or above in accordance with the requirements set out in Appendix A; and

(f) it provides a \textbf{circuit breaker failure protection system}, that need not be duplicated, for each \textbf{circuit breaker} at voltages of 220 kV a.c. or above. \textbf{Circuit breaker} duplication is not required; and

(g) protection system design for a \textbf{connection} connection of \textbf{assets} to the \textbf{grid} at lower voltages must be similar to existing design practice in adjacent \textbf{connections} connections of \textbf{assets} to ensure coordination of protection systems.

(5) At a \textbf{point of connection}—

(a) an \textbf{asset owner}, other than a \textbf{grid owner}, must provide a means of checking \textbf{synchronisation} before the switching of \textbf{assets} if it is possible that such switching may result in \textbf{electrical connection} of parts of the New Zealand electric power system that are not \textbf{synchronised}; and

(b) a \textbf{grid owner} must provide a means of checking \textbf{synchronisation} before the switching of \textbf{assets} in locations agreed with the \textbf{system operator} so that it is not possible for such switching to result in \textbf{electrical connections} of parts of the New Zealand electric power system that are not \textbf{synchronised}.

(6) An auto-reclose facility at the \textbf{grid interface}, at which power flows into the \textbf{grid} can occur, must include an appropriate \textbf{synchronising} check facility.

5 \textbf{Specific requirements for generators}

(1) Each \textbf{generator} must ensure that—

(a) each of its \textbf{generating units}, and its associated \textbf{control systems},—

(i) supports the \textbf{system operator} to plan to comply, and to comply, with the \textbf{principal performance obligations}; and

(ii) is able to \textbf{synchronise} at a stable frequency within the frequency range stated in the \textbf{asset capability statement} for that \textbf{asset}; and

(b) the rate of change in the output of any of its \textbf{generating units} does not adversely affect the \textbf{system operator}'s ability to plan to comply, and to comply, with the
**principal performance obligations.** The rate of change must be adjustable to allow for changes in grid conditions; and

(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% to 7%; and
   (iii) does not adversely affect the operation of the grid because of any of its non-linear characteristics; and

(d) appropriate speed governor settings to be applied before commencing **system tests** for a generating unit are agreed between the system operator and the generator. The performance of the generating unit is then assessed by measurements from system tests and final settings are then applied to the generating unit before making it ready for service after those final settings are agreed between the system operator and the generator. An asset owner must not change speed governor settings without system operator approval.

(2) Each grid-connected generator directly connected to the grid must—

(a) have an excitation and voltage control system with a voltage set point that is adjustable over the range of voltage set out in clause 8.23 and operates continuously in the voltage control mode when synchronised; and

(b) in order to meet the **asset owner performance obligations**, ensure that each of its generating units is equipped with either—
   (i) a connection transformer with an appropriate range of taps on each transformer together with an on-load tap-changer; or
   (ii) assets to give a dynamic performance equivalent to those required by subparagraph (i).

(3) If the output of more than 1 generating unit is controlled by a common control system, the generator must ensure that—

(a) the common control system does not adversely affect the ability of the system operator to plan to comply, and to comply, with the **principal performance obligations**; and

(b) the combined output from the generating units performs as though it were from 1 generating unit; and

(c) the control system does not degrade the individual performance of any one generating unit.

(4) Each generator and grid owner must ensure that each of its assets is capable of operating under the voltage imbalance conditions stated in clause 4.9 of the **Connection Code** and, when operated within the limits stated in its asset capability statement, does not—

(a) contribute unbalanced phase currents into the grid; or

(b) aggravate any current imbalance that may occur on the grid.

(5) At some **points of connection**, a generator must ensure that its generating units have both main protection systems and back-up protection systems for nearby faults on the grid, if the necessity for, and the method of providing, such protection systems is agreed between the system operator and the generator.

### 6 Specific requirements for connected asset owners

Each connected asset owner must agree with the system operator any temporary or permanent connection of the connected asset owner’s assets if those assets
become simultaneously connected to the grid at more than 1 point of connection.

7 Modifications and changes to assets
(1) Assets that have been modified, or are proposed to be modified, are deemed to be new assets for the purposes of this Code and this Technical Code and are subject to the requirements for connection to the grid and the requirements for commissioning assets. For the purposes of this Schedule, the following are considered to be modifications to assets, if the new connection or alteration may affect the capacity of the assets or may affect asset owner performance obligations or technical code requirements:
   (a) a new connection of assets to the grid or a local network;
   (b) a new connection of assets to form part of the grid;
   (c) a new connection of an embedded generator to a local network other than an excluded generator as defined in clause 8.21(1);
   (d) an alteration to assets already connected to the grid or, in the case of embedded generator, already connected to a local network.

(2) The asset owner must notify the system operator in a timely manner of any assets that have been decommissioned if the assets affect or could affect the system operator’s ability to comply with its principal performance obligations.

8 Records, tests and inspections
(1) Each asset owner must arrange for, and retain, records for each of its assets to demonstrate that the assets comply with the asset owner performance obligations and this technical code.

(2) In addition to the requirements for commissioning or testing in clause 2(6) to (8), each asset owner must carry out periodic testing—
   (a) of its assets in accordance with Appendix B; and
   (b) in the case of an asset owner that is an extended reserve provider, of assets specified in its statement of extended reserve obligations in accordance with that statement.

(3) If the system operator advises an asset owner that it reasonably believes that an asset may not comply with an asset owner performance obligation or this technical code, the asset owner must—
   (a) as soon as practicable, but no later than 30 days after receiving a written request, advise the system operator of its remedial or test plan for the assets; and
   (b) as soon as reasonably practicable undertake any remedial action or testing of its assets in accordance with its plan advised to the system operator in paragraph (a).

The system operator may require such testing or remedial action to be undertaken in the presence of a system operator representative.

(4) Each asset owner must, at the request of the system operator, provide access to records of the performance or testing of an asset and access to inspect an asset.
3 Specific requirements for duplicated main protection systems

Duplicated main protection systems (the 2 components of which are referred to in this appendix as main 1 protection and main 2 protection) at voltages of 220 kV a.c. or above must meet the requirements set out below:

(a) duplicated main protection systems must be designed with sufficient coverage and probability of detection that if any or all parts of 1 main protection system fail, the other main protection system electrically disconnects disconnects a faulted asset before a back up protection system initiates the electrical disconnection disconnection of other non-faulted assets;

(b) the d.c. supply to duplicated main protection systems must consist of 2 independent station batteries, each with its own charger, supervision, and with a capacity and carry over duty to cover charger failure until repair and restoration. Station batteries may only feed a common primary d.c. busbar provided that the busbar is insulated and isolated from earth;

(c) the d.c. supply to each duplicated main protection system must be independently fused at the primary d.c. busbar;

(d) the manufacturer of main 1 protection must not be the same as the manufacturer of main 2 protection, unless one protection uses different measurement principles from the other;

(e) the current transformer core (or an equivalent instrument) and the cabling associated with that current transformer core or equivalent instrument (as the case may be) used for main 1 protection must be independent from that used for main 2 protection;

(f) if a voltage transformer supply is required for main 1 or main 2 protection—
   (i) the supply must be fused at the voltage transformer; and
   (ii) the supply for main 1 protection must use an independent fuse and cable from those used for main 2 protection;

(g) main 1 protection must use, in each of the circuit breakers tripped by that main 1 protection, an independent trip coil from that used for main 2 protection;

(h) if protection signalling is used, main 1 protection must use a signal channel over an independent bearer on a different route from that used for main 2 protection;

(i) main 1 protection cabling must be segregated from main 2 protection cabling in a manner that minimises the risk of common mode failure of main 1 and 2 protection and minimises the number of connections connections in any protection circuit.

4 Existing equipment

Despite clauses 1 and 3—

(a) a current transformer commissioned commissioned before 31 May 2007 is not required to comply with clause 3(e) until the current transformer is replaced; and

(b) a circuit breaker commissioned commissioned before 31 May 2007, if not designed to incorporate a second trip coil, is not required to comply with clause 3(g) until the circuit breaker is replaced; and

(c) cabling commissioned commissioned before 31 May 2007, if not designed to be segregated, is not required to comply with the segregation requirements of clause 3(i) until the cabling is replaced.
Schedule 8.3, Technical Code B

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** to manually **electrically disconnect** demand at each **point of connection** are specified.

5 **Formal notices and responses**

(1) The **system operator** must issue a notice either orally or in writing to relevant **participants** whenever, or as soon as practicable after, any of the following events has occurred:
(a) the ability of the **system operator** to plan to comply, and to comply, with the **principal performance obligations** is at risk or is compromised (as set out in the **policy statement**):
(b) public safety is at risk:
(c) there is a risk of significant damage to **assets**:
(d) independent action has been taken in accordance with this **technical code** to restore the **system operator’s principal performance obligations**.

(1A) The **system operator** must issue a notice in writing to all **participants** whenever, or as soon as practicable after, an **island wide instruction** to **electrically disconnect** demand has been issued, amended, or revoked under clause 6.

(1B) For the purposes of subclause (1A), an **island wide instruction** is when the electrical or geographical region affected by a notice is all of an **island**.

(1C) The **system operator** must provide any notice issued under subclause (1A) to the **pricing manager** by 0730 hours on the following **trading day**.

(2) The **system operator** must ensure that a **formal notice** issued in accordance with subclause (1) or subclause (1A) includes the following:
(a) the electrical or geographical region affected by the notice:
(b) the potential consequences of the situation:
(c) the responses requested of **participants**:
(d) the **trading periods** to which the notice applies.

(3) The **system operator** must record the issue of a **formal notice**, and each **participant** must record receipt of a **formal notice**.

(4) If the **system operator** issues a request in accordance with this **technical code** to a **participant**, the **participant** must use reasonable endeavours to respond to the request.

6 **Actions to be taken by the system operator in a grid emergency**

(1) If insufficient generation and **frequency keeping** gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:
(a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure there is sufficient generation and **frequency keeping**;
(b) request that a **purchaser** or a **connected asset owner** reduce **demand**:
(c) require a grid owner to reconfigure the grid:
(d) require the electrical disconnection of demand in accordance with clause 7A:
(e) take any other reasonable action to alleviate the grid emergency.

(2) If insufficient transmission capacity gives rise to a grid emergency, the system operator may, having regard to the priority below, if practicable, and regardless of whether a formal notice has been issued, do 1 or more of the following:
(a) request that a generator varies its offer and dispatch the generator in accordance with that offer, to ensure that the available transmission capacity within the grid is sufficient to transmit the remaining level of demand:
(b) request that an asset owner restores its assets that are not in service:
(c) request that a purchaser or connected asset owner reduces its demand:
(d) require the electrical disconnection of demand in accordance with clause 7A:
(e) take any other reasonable action to alleviate the grid emergency.

(3) If frequency is outside the normal band and all available injection has been dispatched, the system operator may require the electrical disconnection of demand in accordance with clause 7A in appropriate block sizes until frequency is restored to the normal band.

(4) If any grid voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1), and is sustained at or below that limit, the system operator may require the electrical disconnection of demand in accordance with clause 7A in appropriate block sizes until the voltage is restored to above the minimum voltage limit.

(5) The system operator may, if an unexpected event occurs giving rise to a grid emergency, take any reasonable action to alleviate the grid emergency.

7A Emergency load shedding must maintain a process for
(1) Each connected asset owner must maintain a process for electrical disconnection of demand for points of connection.
(2) The process must specify the participant that will effect the electrical disconnection of demand.
(3) The connected asset owner must obtain agreement for the process from the system operator and each grid owner.
(4) Each connected asset owner must advise the system operator of the agreed process in addition to any changes to a process previously advised.
(5) If the system operator requires the electrical disconnection of demand under this technical code, the system operator must instruct connected asset owners and grid owners in accordance with the agreed process under subclause (3) to electrically disconnect demand for the relevant point of connection.
(6) If the system operator and a connected asset owner or grid owner have not agreed on a process for electrical disconnection of demand at a point of connection, the system operator must instruct grid owners to electrically disconnect demand directly at the relevant point of connection.
(7) To the extent practicable, the system operator must use reasonable endeavours when instructing the electrical disconnection of demand to ensure equity between connected asset owners.
Each connected asset owner or grid owner must act as instructed by the system operator operating under clause 6.

7B Obligations of extended reserve providers in relation to automatic under-frequency load shedding

(1) On the operation of extended reserve that is an automatic under-frequency load shedding system, an extended reserve provider—
   (a) must, as soon as practicable, advise the system operator of the operation of the automatic under-frequency load shedding system and, if reasonably required by the system operator to plan to comply, or to comply, with its principal performance obligations, a reasonable estimate of the amount of demand that has been electrically disconnected; and
   (b) may electrically connect demand only when permitted to do so by the system operator; and
   (c) must ensure demand restored electrically connected under paragraph (b) complies with the obligations in its statement of extended reserve obligations; and
   (d) must report to the system operator if demand is moved between points of connection; and
   (e) may request permission to electrically connect demand from the system operator if no instruction to electrically connect demand is received from the system operator within 15 minutes of the frequency returning to the normal band; and
   (f) may cautiously and gradually restore electrically connect demand that has been disconnected through the automatic under-frequency load shedding system if there is a loss of communication with the system operator, 15 minutes after the loss of communication occurred.

(2) An extended reserve provider may electrically connect demand only while frequency is within the normal band and voltage is within the required range.

(3) Each extended reserve provider must immediately cease the electrically connect restoration of demand and, to the extent necessary, electrically disconnect demand, if the frequency drops below the normal band or the voltage moves outside the required range.

(4) As soon as practicable after communications are restored, each extended reserve provider must report to the system operator on the status of electrically connect of load restoration and the status of re-arming the automatic under-frequency load shedding system.

8 Obligations of grid owners

(1) A grid owner must use reasonable endeavours to ensure that appropriate assets are installed for the manual electrically disconnect demand at points of connection.

(2) A grid owner must take independent action as may be required by the system operator in accordance with clause 6(4), to electrically disconnect demand at points of connection when any grid voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1) and is sustained at or below that level. A grid owner must continue to electrically disconnect demand at points of connection while the
voltage remains below that minimum voltage limit, being guided by any arrangements with connected asset owners as advised by the system operator.

9 Obligations of generators and ancillary service agents to take independent action

The following independent action is required of generators and ancillary service agents during the occurrence of extreme variations of frequency or voltage at the points of connection to which their assets are connected (such extreme levels of frequency or voltage are deemed to constitute a grid emergency and require a fast and independent response from each generator and each ancillary service agent):

(a) when the under-frequency limit is reached and the frequency continues to fall, each generator must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:
   (i) increase the energy injection from each generating unit that is physically capable of increasing such injection:
   (ii) attempt to restore grid frequency to the normal band by synchronising, connecting to the grid and loading each generating unit that is not electrically connected but is able to be electrically connected and operated in this manner:
   (iii) re-synchronise, re-connect to the grid and load each generating unit that has tripped and is able to be electrically connected and operated in this manner:
   (iv) report to the system operator as soon as practicable after taking action in accordance with subparagraphs (i) to (iii):

(b) when the over frequency limit is reached and the frequency continues to rise, each generator must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:
   (i) decrease the energy injection from electrically connected generating units if the generator is physically capable of decreasing such injection:
   (ii) report to the system operator as soon as practicable after taking action in accordance with subparagraph (i):

(c) when either the minimum voltage limit or the maximum voltage limit set out in the table contained in clause 8.22(1) is exceeded at any point of connection, generators and ancillary service agents must use reasonable endeavours to take immediate independent action to return the voltage to, as close as practicable, within such limits. Each generator must use reasonable endeavours to synchronise, connect to the grid and, as necessary, load and adjust all available generating units that can assist in restoring the voltage. Ancillary service agents must also use reasonable endeavours to electrically connect to the grid and, as necessary, load all available reactive capability resources, that can assist in restoring the voltage. As soon as practicable after taking such actions, each generator and ancillary service agent must report to the system operator on the action taken to correct voltage:

(d) for a loss of communication with the system operator, lasting at least 5 minutes, each generator must use reasonable endeavours to—
   (i) for synchronised generating units, take independent action to adjust supply to maintain frequency as close as possible to the normal band, and maintain voltage as close as possible either to that previously advised by the system operator, or as can be best established by the generator; and
(ii) synchronise and connect available generating units to the grid if the generating units currently electrically connected do not have the capacity to control the frequency and voltage as required by paragraph (e)(i); and

(iii) continue to attempt to maintain the frequency and voltage to meet the requirements of paragraph (e)(i); and

(iv) as soon as practicable after communications are restored, report to the system operator on the action taken:

(e) for a loss of communication with the system operator lasting at least 5 minutes, ancillary service agents must use reasonable endeavours to—

(i) if on load, take independent action to adjust any real or reactive power resources to maintain frequency and voltage as close as possible either to that previously advised by the system operator or as can be best established by the ancillary service agent; and

(ii) electrically connect available reactive capability resources to the grid if the currently electrically connected reactive power resources do not have the capacity to control the voltage above the minimum limit set out in the table contained in clause 8.22(1); and

(iii) continue to attempt to maintain the voltage above the minimum limit set out in the table contained in clause 8.22(1); and

(iv) as soon as practicable after communications are restored, report to the system operator on the action taken:

(f) in the event of a failure at the system operator’s operational centre that disables the main dispatch or communication systems, the system operator may temporarily transfer its operational activities to an alternative operational centre, and the system operator must arrange for communication facilities to transfer to the new location and must notify participants of those arrangements.

Schedule 8.3, Technical Code C, Appendix A

Appendix A: Indications and Measurements
(Clause 9(1)-(3) of Technical Code C)

Table A1: Requirements of generators

Each generator must provide the indications and measurements in Table A1. If net (or gross) measurements are required in Table A1, the use of scaling factors together with the provision of the relevant gross (or net) values is acceptable with the system operator’s approval. Each generator must provide scaling factors to the grid owner so that the grid owner can apply the adjustment at the SCADA server.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy(^a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station net MW</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Generating unit gross MW(^1)</td>
<td>Import and export, for each generating unit</td>
<td>±2%</td>
</tr>
<tr>
<td>Station net Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Generating unit gross Mvar(^1)</td>
<td>Import and export, for each generating unit</td>
<td>±2%</td>
</tr>
<tr>
<td>Indication or measurement</td>
<td>Values required</td>
<td>Accuracy³</td>
</tr>
<tr>
<td>---------------------------------------------------</td>
<td>------------------------------------------------------</td>
<td>-----------</td>
</tr>
<tr>
<td>Generating unit circuit breaker status¹</td>
<td>Open/closed/in transition/indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface circuit breaker status</td>
<td>Open/closed/in transition/indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface disconnector status</td>
<td>Open/closed/in transition/indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Special protection scheme status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Maximum output capacity of generating station</td>
<td>Number of connected generating units × MW capability of each generating unit</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table A2: Requirements of grid owners:

Each grid owner must provide the indications and measurements shown in Table A2 in respect of assets connected to, or forming part of, the grid.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid interface circuit breaker status</td>
<td>Open/closed/in transition/indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface disconnector status</td>
<td>Open/closed/in transition/closed to earth/indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface auto reclose status</td>
<td>Enabled/disabled/operated/locked out</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface MW</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Grid interface Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Circuit Amps</td>
<td>Current at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td>Circuit MW</td>
<td>MW at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td>Circuit Mvar</td>
<td>Mvar at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td>Special protection scheme status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Tap positions for interconnecting transformers and supply transformers with on-load tap changers</td>
<td>Tap position for all windings including tapped tertiaries</td>
<td>N/A</td>
</tr>
<tr>
<td>Tap positions for interconnecting transformers and supply transformers with off-load tap changers⁴</td>
<td>Tap position for all windings including tapped tertiaries</td>
<td>N/A</td>
</tr>
<tr>
<td>Reactive plant (eg RPC equipment, capacitor, reactor, condenser) Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Bus voltage</td>
<td>kV</td>
<td>±2%</td>
</tr>
<tr>
<td>Special protection scheme status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>HVDC modulation status</td>
<td>Frequency stabiliser/spinning reserve sharing/Haywards frequency control/AC transient voltage support</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Table A3: Requirements of connected asset owners

Each connected asset owner must provide the indications and measurements shown in Table A3 in respect of assets connected to, or forming part of, the grid.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy(^2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid interface circuit breaker status</td>
<td>Open/ closed/ in transition/ indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface disconnector status</td>
<td>Open/ closed/ in transition/ indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface auto reclose status</td>
<td>Enabled/disabled/operated/locked out</td>
<td>N/A</td>
</tr>
<tr>
<td>Special protection scheme status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Reactive plant(^5) (eg RPC equipment, capacitor, reactor, condenser) Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
</tbody>
</table>

\(^1\) Required only if a generating unit has a maximum continuous rating of greater than 5 MW.

\(^2\) No intentional time delays should be included for circuit breaker indications as these are time tagged by the system operator to less than 10 ms.

\(^3\) If accuracy is measured at the input terminal of the RTU of the grid owner, under normal operating conditions at full scale.

\(^4\) Indication required within 5 minutes of status change.

\(^5\) Required only if reactive plant has a maximum continuous rating of greater than 5 Mvar.

Part 9

9.21 Qualifying customers

(1) A retailer’s qualifying customer is a person who, as at the end of the qualifying date, —

(a) is a customer of the retailer; and

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

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

(ii) there was consumption, in the previous year, of 3000 kWh or more.

(2) Despite subclause (1), a person is not a qualifying customer if the price of all of the electricity provided under the person’s contract with the retailer for the supply of electricity is determined by reference to the final price at a GXP.

(3) For the purposes of subclause (1)(b)(ii), if a qualifying customer’s previous year’s consumption at the ICP is not available to the retailer, the retailer must make a reasonable estimate of the consumption.

(4) To avoid doubt,—

(a) there is no qualifying customer at an ICP if, at the end of the qualifying date,—

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

(ii) the ICP is electrically disconnected;

(b) a retailer’s qualifying customers includes a customer who switched—

(i) to the retailer from another retailer on or before the qualifying date, including during a public conservation period; or
(ii) from the retailer to another retailer between the qualifying date and the date on which the retailer pays compensation under the customer compensation scheme.

Part 10

10.7 Access to premises in which metering installation located

(1) In this clause, access to a metering installation—
   (a) means physical access to the premises in which the metering installation is located; but
   (b) does not include access to the following, which are dealt with in Schedule 10.6:
      (i) raw meter data from the metering installation; and
      (ii) the metering installation itself and its metering components.

(2) A reconciliation participant must, upon receiving a request from 1 of the following parties, arrange access to a metering installation for which it is responsible:
   (a) the Authority:
   (b) an ATH:
   (c) an auditor:
   (d) a metering equipment provider:
   (e) a gaining metering equipment provider.

(3) A party listed in subclause (2) may only request access to the metering installation for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in connection with relation to 1 or more of the following:
   (a) the party’s audit functions:
   (b) the party’s administration functions:
   (c) the party’s testing functions:
   (d) the provision of metering components.

(4) A reconciliation participant who is required to give a party listed in subclause (2) access to a metering installation must use its best endeavours to do so—
   (a) in accordance with the authorisation, and any conditions or restrictions contained in the authorisation, referred to in subclause (5); and
   (b) subject to and to the extent allowed by the authorisation, in a manner and within a timeframe which are appropriate in the circumstances, to enable the party to exercise the party’s rights, or perform the party’s obligations, that are dependent, either directly or indirectly, on access being given.

(5) If the reconciliation participant referred to in subclause (2) is a trader responsible for an ICP that—
   (a) has a consumer, the trader must have obtained the authorisation from the consumer to access the metering installation before arranging access; or
   (b) does not have a consumer, the trader must arrange for access to the metering installation.

(6) The reconciliation participant must arrange for the party listed in subclause (2) to be provided with any necessary facilities, codes, keys, or other means to enable the party to obtain access to the metering installation by the most practicable means.
10.24 Responsibility for ensuring there is metering installation for ICP that is not also NSP
A trader must, for each energised electrically connected ICP that is not also an NSP, and for which it is recorded in the registry as being responsible, ensure that—
(a) there is 1 or more metering installations; and
(b) all electricity conveyed is quantified in accordance with this Code; and
(c) it does not use subtraction to determine submission information for the purposes of Part 15.

10.26 Responsibility for ensuring there is metering installation for point of connection to grid
(1) A grid owner must, for each GXP which connects to its grid, ensure that there is 1 or more certified metering installations for the GXP.
(2) An asset owner must, for each GIP which connects to the grid, ensure that there is 1 or more certified metering installations for the GIP.
(3) A participant who proposes to connect to the grid at a new point of connection must take all practicable steps and use its best endeavours to agree with the grid owner and any other affected participants, on which participant will provide the metering installation for the proposed new point of connection.
(4) If the participants cannot agree, within 60 business days of the grid owner first being advised of the proposed new point of connection to the grid, on the participant to be responsible for providing the metering installation,—
(a) any affected participant may advise the market administrator—
   (i) that agreement has not been reached; and
   (ii) of the identity of all affected participants; and
   (iii) of the reasons (if and to the extent known) that agreement was not reached; and
(b) the market administrator must determine which participant must provide the metering installation; and
(c) the market administrator must advise—
   (i) the relevant participant of its responsibility to provide the metering installation; and
   (ii) the participant intending to connect to the grid of its determination; and
   (iii) the grid owner of its determination.
(5) When determining which participant is responsible for providing the metering installation, the market administrator must, unless it is satisfied that there is good reason not to do so, do so on the basis that—
(a) the grid owner is responsible if the market administrator anticipates that the point of connection is a GXP; and
(b) the participant connecting assets to the grid at the point of connection is responsible if the market administrator anticipates that the point of connection is a GIP.

10.28 Connecting and temporarily electrically connecting point of connection
(1) A grid owner may electrically connect a point of connection to the grid.
(2) A distributor that initiates the creation of an NSP on its network under Part 11 may electrically connect the NSP to—
(a) an **embedded network**, if the **embedded network** owner has agreed to the connection; or
(b) a **local network**, if the **local network** owner has agreed to the connection.

(3) An **embedded network** owner that initiates the creation of an **NSP** on its network under Part 11 may electrically connect the **NSP** to another **embedded network** if the other **embedded network** owner has agreed to the connection.

(4) A **distributor** may electrically connect an **ICP** that is not an **NSP**.

(5) No other **participant** may effect an electrical connection to which subclauses (1) to (4) apply.

(5A) A **metering equipment provider** may request a **point of connection** be temporarily electrically connected for the purposes of carrying out, at that **point of connection**,—
(a) the activities or processes necessary for, or as part of, the certification of a **metering installation**; or
(b) the maintenance, repair, testing, or commissioning of a **metering installation**.

(6) Despite subclause (5A), a **metering equipment provider** must not request the temporary energisation of a new **point of connection** be temporarily electrically connected unless—
(a) the **metering equipment provider** is authorised to do so by the **reconciliation participant** responsible for the **point of connection**; and
(b) the **metering equipment provider** has an arrangement with that **reconciliation participant** to provide metering services.

(7) A **network** owner must not electrically connect a new **point of connection** to its **network** that is to be quantified with a category 1 **metering installation**, or higher category of **metering installation**, unless requested to do so by—
(a) the **metering equipment provider**, for the purposes in subclause (5A) a temporary energisation of the **point of connection**; or
(b) the **reconciliation participant** responsible for ensuring there is a **metering installation**, for the **point of connection**.

10.29 Electrically connecting point of connection to grid

(1) Despite clause 10.28(1), a **grid owner** must not electrically connect a **point of connection** to the **grid** unless it has—
(a) ensured that the processes described in clause 10.26 have been carried out; and
(b) requested, in the prescribed form, not less than 20 business days before the proposed **connection** date, authorisation from the **market administrator**, to connect the **point of connection**; and
(c) obtained the authorisation referred to in paragraph (b) from the **market administrator**.

(2) The **grid owner** must, within 5 business days of electrically connecting a **point of connection** to the **grid**, advise the **reconciliation manager** of—
(a) the **point of connection** that has been connected; and
(b) the **connection** date.
10.30 **Connecting and temporarily electrically connecting NSP that is not point of connection to grid**

(1) Despite clause 10.28(2), a *distributor* must not connect an *NSP* unless a *reconciliation participant* has requested the connection.—

(a) must not electrically connect an *NSP* unless a *reconciliation participant* has requested the connection; but

(b) may electrically connect an *NSP* if a *metering equipment provider* has requested temporary energisation of the *NSP*.

(2) A *distributor* must, within 5 business days of electrically connecting an *NSP*, advise the *reconciliation manager* of the following:

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

(b) the connection date; and

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

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

(3) A *distributor* may temporarily electrically connect an *NSP* if a *metering equipment provider* has requested that the *NSP* be temporarily electrically connected for the purposes of carrying out, at that *NSP*,—

(a) the activities or processes necessary for, or as part of, the certification of a metering installation; or

(b) the maintenance, repair, testing, or commissioning of a metering installation.

10.31 **Connecting and temporarily electrically connecting ICP that is not NSP**

(1) Despite clause 10.28(4), a *distributor* must not connect an *ICP* that is not an *NSP* unless the *trader* trading at the *ICP* has requested the connection.—

(a) the *trader* trading at the *ICP* has requested the connection; or

(b) the *metering equipment provider* who has an arrangement with the *trader* trading at the *ICP* has requested temporary energisation of the *ICP*.

(2) A *distributor* may temporarily electrically connect an *ICP* that is not an *NSP* if a *metering equipment provider* has requested that the *ICP* be temporarily electrically connected for the purposes of carrying out, at that *ICP*,—

(a) the activities or processes necessary for, or as part of, the certification of a metering installation; or

(b) the maintenance, repair, testing, or commissioning of a metering installation.

10.32 **Reconciliation participant requesting electrical connection of point of connection**

A *reconciliation participant* must only request the electrical connection of a point of connection if the *reconciliation participant*—

(a) accepts responsibility for the *reconciliation participant’s* obligations in this Part and Parts 11 and 15 for the point of connection; and

(b) has an arrangement with a *metering equipment provider* to provide 1 or more metering installations for the point of connection.

10.33 **Energisation of electrically connecting point of connection**

(1) A *reconciliation participant* may energise electrically connect a point of connection, or authorise a point of connection to be energised electrically connected, if—
(a) the reconciliation participant is recorded in the registry as being responsible for the ICP; and
(b) 1 or more certified metering installations are in place in accordance with this Part; and
(c) in the case of an ICP that has not previously been energised electrically connected, the owner of the network to which the point of connection is connected has given written approval.

(2) A reconciliation participant that meets the requirements of subclause (1)(a)—
(a) may authorise a metering equipment provider, with which it has an arrangement, to request the temporary energisation of a point of connection be temporarily electrically connected, for the purposes of carrying out, at that point of connection,
   — (i) the activities or processes necessary for, or as part of, the certification of a metering installation; or
   (ii) the maintenance, repair, testing, or commissioning of a metering installation;
(b) may authorise energisation of that an ICP be electrically connected if—
   (i) a metering installation is in place at the ICP; and
   (ii) the metering installation is operational but not certified; and
   (iii) the reconciliation participant arranges for the certification of the metering installation to be completed within 5 business days of the energisation date of being electrically connected;
(c) may energise electrically connect an ICP if the point of connection is solely for unmetered load.

(3) A reconciliation participant must not authorise the energisation of a point of connection be electrically connected in any of the following circumstances:
(a) a distributor has de-energised electrically disconnected the point of connection for safety reasons, and has not subsequently approved the energisation of the point of connection be electrically connected;
(b) the energisation of electrically connecting the point of connection would breach the Electricity (Safety) Regulations 2010.

(4) No participant may energise electrically connect a point of connection, or authorise the energisation of a point of connection be electrically connected, other than a reconciliation participant as described in subclauses (1) to (3).

10.36 Reconciliation participant to have arrangement with metering equipment provider
A reconciliation participant must, before accepting responsibility to be the reconciliation participant for a point of connection, enter into an arrangement with a metering equipment provider—
(a) for the reconciliation participant to provide the metering equipment provider with physical access to the metering installation for the point of connection and the premises at which it is situated; and
(b) arranging for the point of connection to be electrically disconnected—de-energisation if required by the metering equipment provider to enable the metering equipment provider to comply with its obligations under this Part; and
(c) for the metering equipment provider to provide the reconciliation participant
with access at the services access interface to the metering data from the metering installation for the point of connection, in accordance with an authorisation from—
(i) in the case of an ICP, the consumer; or
(ii) in the case of an NSP, the network owner.

10.39 Responsibility for metering infrastructure integration

(1) A metering equipment provider must ensure that—
(a) for each metering installation for which it is responsible, an appropriately designed metering infrastructure is in place; and
(b) in each metering installation for which it is responsible,—
(i) each metering component is compatible with, and will not cause any interference with the operation of, any other metering component in the metering installation; and
(ii) collectively, all metering components integrate to provide a functioning system; and
(c) each metering installation for which it is responsible is correctly and accurately integrated within the associated metering infrastructure.

(2) Subclause (1) does not apply to an electrically disconnected de-energised metering installation for an ICP.

Schedule 10.6

1 Metering equipment provider must provide access to raw meter data

(1) A metering equipment provider must, within 10 business days of receiving a request from a trader with whom it has an arrangement to access raw meter data from a metering installation for which the metering equipment provider is responsible, give remote or onsite access at the services access interface to the trader to collect, obtain, and use raw meter data from the metering installation.

(2) A metering equipment provider may, if it receives a request from a person with whom it has an arrangement, other than a trader under subclause (1), to access raw meter data from a metering installation for which the metering equipment provider is responsible, give remote or onsite access at the services access interface to the person to collect, obtain, and use raw meter data from the metering installation.

(3) A metering equipment provider must only give access to a trader under subclause (1), or a person under subclause (2), if the trader or person has entered into a contract to collect, obtain, and use the raw meter data, with the consumer whose electricity is measured or estimated, or whose load is controlled at the metering installation.

(4) A metering equipment provider must, within 10 business days of receiving a request from 1 of the following parties, give the party access to raw meter data from a metering installation for which it is responsible:
(a) a relevant reconciliation participant with whom it has an arrangement, other than a trader:
(b) the Authority:
(c) an ATH:
(d) an auditor.

(5) A party listed in subclause (4) may only request access to raw meter data for the purposes
of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in relation to connection with 1 or more of the following:
(a) the party’s audit functions:
(b) the party’s administration functions:
(c) the party’s testing functions:
(d) the provision of submission information to the reconciliation manager.

(6) The metering equipment provider must provide a trader under subclause (1) or a party under subclause (4) with—
(a) the raw meter data; or
(b) any necessary facilities, codes, keys, or other means to enable the trader or party to access the raw meter data by the most practicable means.

(7) The metering equipment provider must, when complying with subclause (6), or when providing access to a person under subclause (2), use appropriate procedures to ensure that—
(a) the raw meter data is received only by—
   (i) the trader, person, or party; or
   (ii) a contractor to a trader, person, or party; and
(b) the security of the raw meter data and the metering installation is maintained; and
(c) access to raw meter data under subclauses (1) to (6) is limited to only the specific raw meter data—
   (i) authorised by a contract described in subclause (3), in the case of a trader under subclause (1) or a person under subclause (2); or
   (ii) required for the purposes of exercising the party’s rights and performing the party’s obligations under this Code, any relevant regulations, or the Act in connection with relation to the party’s audit, administration, and testing functions, in the case of a party referred to in subclause (4).

(8) Nothing in this Part affects proprietary interests in metering data.

3 Metering equipment provider must provide access to metering installation

(1) A metering equipment provider must, within 10 business days of receiving a request from 1 of the following parties, arrange physical access to each metering component in a metering installation for which it is responsible:
(a) a relevant reconciliation participant with whom it has an arrangement, other than a trader:
(b) the Authority:
(c) an ATH:
(d) an auditor:
(e) a gaining metering equipment provider.

(2) A party listed in subclause (1) may only request physical access to a metering component in the metering installation for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in connection with relation to 1 or more of the following:
(a) the party’s audit functions:
(b) the party’s administration functions:
(c) the party’s testing functions:
(d) the provision of metering components.
(3) The **metering equipment provider** must arrange for a party under subclause (1) to be provided with any necessary facilities, codes, keys, or other means to enable the party to obtain physical access to all **metering components** in the **metering installation** by the most practicable means.

(4) In complying with subclause (3), the **metering equipment provider** must use appropriate procedures to ensure that—
   (a) the security of the **metering installation** is maintained; and
   (b) physical access to the **metering installation** under subclause (1) is limited to only the physical access required for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant **regulations** in connection with relation to the party’s **audit**, administration, and testing functions.

(5) If a party referred to in subclause (1) requires urgent physical access to a **metering installation**, it must advise the relevant **metering equipment provider**, giving all relevant particulars of the physical access required and the reason for the urgency, and the **metering equipment provider** must use its best endeavours to arrange physical access in accordance with the requested urgency.

5 **Metering equipment provider to provide access to metering records**

   (1) A **gaining metering equipment provider** may request that a **losing metering equipment provider** provide it with access to **metering records** required for the **gaining metering equipment provider** to exercise its rights and perform its obligations under this Code or any relevant **regulations** in connection with relation to its respective **auditing**, administration, and testing functions.

   (2) The **losing metering equipment provider** must, within 10 **business days** of receiving a request under subclause (1), provide the **gaining metering equipment provider** with—
      (a) the **metering records**; or
      (b) any necessary facilities, codes, keys, or other means to enable the **gaining metering equipment provider** to obtain access to the **metering records** by the most practicable means.

   (3) In complying with subclause (2), the **losing metering equipment provider** must use appropriate procedures to ensure that—
      (a) the **metering records** are received only by the **gaining metering equipment provider** or its contractor; and
      (b) the security of the **metering records** is maintained; and
      (c) it only provides access to the specific **metering records** required for the purposes of the **gaining metering equipment provider** exercising its rights and performing its obligations under this Code or any relevant **regulations** in connection with relation to its **auditing**, administration, and testing functions.

Schedule 10.7

5 **Determination of metering installation category**

   An ATH must, before it **certifies** a **metering installation**, determine the category of the **metering installation** in accordance with the following:
   (a) subject to clause 6, if the **metering installation** incorporates a current transformer, its category must be determined according to the primary current rating of the current transformers.
transformer and the connected voltage set out in Table 1 of Schedule 10.1:
(b) if the metering installation does not incorporate a current transformer and the quantity of electricity conveyed is measured by a meter, it must be category 1.

15 Recertification programme
(1) A metering equipment provider must have a recertification programme for all metering installations for which it is responsible to ensure that each metering installation is recertified prior to the expiry date of its then current certification if the metering installation is not decommissioned.
(2) Subclause (1) does not apply to an electrically disconnected a de-energised metering installation for an ICP.

30 Other equipment using measuring transformer
(1) A metering equipment provider must not permit a measuring transformer, in a metering installation for which it is responsible, to be connected to equipment used at any time for a purpose other than metering, unless it is not practical for the equipment to have a separate measuring transformer.
(2) An ATH must, before it certifies a metering installation incorporating a measuring transformer used by—
   (a) another metering installation, ensure, where voltage transformers are connected to more than 1 meter, that—
      (i) the meters are included in the metering installation being certified; and
      (ii) appropriate fuses or circuit breakers are provided to protect the metering circuit from short circuits or overloads affecting the other meter:
   (b) equipment referred to in subclause (1), ensure that—
      (i) the accuracy of the metering installation remains within the maximum permitted error for the relevant metering installation category set out in Table 1 of Schedule 10.1; and
      (ii) the metering installation certification report confirms that the accuracy of the metering installation remains within the maximum permitted error for the relevant metering installation set out in Table 1 of Schedule 10.1; and
      (iii) any wiring between the equipment and any part of the metering installation has no intermediate joints; and
      (iv) the equipment referred to in subclause (1) is labelled appropriately, including with any de-energisation restrictions regarding being electrically disconnected; and
      (v) the connection details of the equipment referred to in subclause (1) are recorded in the metering installation design report; and
      (vi) appropriate fuses or circuit breakers are provided to protect the voltage transformer and metering circuit from short circuits or overloads affecting the other equipment; and
      (vii) the wiring referred to in subparagraph (iii) is certified as part of the metering installation.
(3) [Revoked]
38 Requirements for certification of metering installation incorporating data storage device

(2) An ATH must, before it certifies a metering installation,—
(a) ensure that each data storage device in the metering installation—

(iv) has appropriate electrical separation between all of its outputs and inputs appropriately electrically isolated and all of its outputs and inputs are rated for purpose; and

Part 11

11.1 Contents of this Part

This Part—
(a) provides for the management of information held by the registry; and
(b) prescribes a process for switching customers and embedded generators between traders; and
(c) prescribes a process for a distributor to change the record in the registry of an ICP so that the ICP is recorded as being usually connected connected to an NSP in the distributor’s network; and
(d) prescribes a process for switching responsibility for metering installations for ICPs between metering equipment providers; and
(e) prescribes a process for dealing with trader events of default; and
(f) requires retailers to give consumers information about their own consumption of electricity; and
(g) requires retailers to give information about their generally available retail tariff plans to any person on request.

11.3 Certain points of connection must have ICP identifiers

(1) This clause applies to the following:
(a) a trader who has agreed to purchase electricity from an embedded generator or sell electricity to a consumer:
(b) an embedded generator who sells electricity directly to the clearing manager:
(c) a direct purchaser connected connected to a local network or an embedded network:
(d) an embedded network owner in relation to a point of connection on an embedded network that is settled by differencing:
(e) a network owner in relation to a shared unmetered load point of connection to the network owner’s network:
(f) a network owner in relation to a point of connection between the network owner's network and an embedded network.

(2) A participant to whom this clause applies must, before the participant assumes responsibility for a point of connection described in subclause (3) on a local network or embedded network, obtain an ICP identifier for the point of connection.
(3) The points of connection for which ICP identifiers must be obtained under subclause (2) are points of connection at which any of the following occurs:
   (a) a consumer purchases electricity from a trader;
   (b) a trader purchases electricity from an embedded generator;
   (c) a direct purchaser purchases electricity from the clearing manager;
   (d) an embedded generator sells electricity directly to the clearing manager;
   (e) a network is settled by differencing;
   (f) there is a distributor status ICP—
      (i) at the point of connection between an embedded network and the distributor’s network; or
      (ii) at the point of connection of shared unmetered load.

11.4 Distributors must create ICP identifiers for ICPs
   (1) Each distributor must create an ICP identifier in accordance with clause 1 of Schedule 11.1 for each ICP on each network for which the distributor is responsible.
   (2) A distributor must create an ICP identifier for the point of connection at which an embedded network connects to the distributor’s network in accordance with subclause (1).
   (3) An ICP identifier for an ICP may not be changed.

11.8 Provision of and changes to ICP information and NSP information by participants
   (1) This clause applies if—
      (a) an NSP is to be created or decommissioned; or
      (b) a distributor wishes to change the record in the registry of an ICP that is not recorded as being usually connected to an NSP in the distributor’s network, so that the ICP is recorded as being usually connected to an NSP in the distributor’s network (a "transfer").
   (2) The participant specified in clause 25(3) of Schedule 11.1 must give the notification required by clause 25(1) of Schedule 11.1.
   (3) A distributor to whom subclause (1)(b) applies must comply with clause 25(2) of Schedule 11.1.
   (4) The participants specified in clauses 25 to 27 of Schedule 11.1 must comply with those clauses.
   (5) If a network owner acquires all or part of an existing network, the network owner must give the notification required by clause 29 of Schedule 11.1.

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 notify the registry, 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 notification under subclause (2) must notify the distributor if it wishes to add an ICP to or omit an ICP from the ICPs across which the unmetered load is shared.
(4) A **distributor** who receives notification under subclause (3) must notify the **registry** and each **trader** responsible for any of the ICPs across which the **unmetered load** is shared of the addition or omission of the ICP.

(5) If a **distributor** becomes aware of a change to the capacity of an ICP across which the **unmetered load** is shared or that an ICP across which the **unmetered load** is shared is **decommissioned**, it must notify all **traders** who receive notification under subclause (2) of the change or decommissioning as soon as practicable after the change or decommissioning.

### 11.17 Electrically Connecting ICP that is not also NSP

(1A) A **distributor** must, when electrically connecting an ICP that is not also an NSP, follow the connection process set out in clause 10.31.

(1) A **distributor** must not electrically connect an ICP across which **unmetered load** is shared unless a **trader** is recorded in the **registry** as accepting responsibility for the shared unmetered load.

(2) A **distributor** must not electrically connect an ICP of any other kind unless a **trader** is recorded in the **registry** as accepting responsibility for the ICP.

(3) Subclause (2) does not apply to an ICP that is—
   (a) the point of connection between a network and an embedded network; or
   (b) the point of connection of shared unmetered load.

### 11.25 Reports to the clearing manager, system operator or reconciliation manager

(1) The **clearing manager**, or the **system operator**, or the **reconciliation manager** may request in writing, no later than 5 business days before the last day of the month before the 1st month for which the report is requested, a report that includes any or all of the following information:

   (a) all active **NSPs** connected to a **local network** during the immediately preceding 14 calendar months:

   (b) all active **NSPs** connected to a **network** for which a **trader** is, and has over the immediately preceding 14 calendar months been, responsible:

   (c) the dates on which each **trader’s** responsibility under this Code at an **NSP** commenced and ceased.

(2) The **system operator** may at any time request, in writing, a report that sets out every switch made under clauses 2, 9 or 14 of Schedule 11.3, the effect of which is that a **trader** has commenced trading at an **NSP** or a **trader** has ceased trading at an **NSP**.

(3) A request made under subclauses (1) or (2) may—

   (a) be a one-off request; or

   (b) specify a frequency over a particular period; or

   (c) specify a frequency over an indefinite period until terminated by the requesting person.

(4) If the request is received by the time specified in this clause, the **registry** must provide the report by 1000 hours on the 1st **business day** of the calendar month following the calendar month in which the request was made, or if the request for the report specifies a later date, by the later date.

(5) The person who requested the report may vary any of the details set out in the request, by giving notification to the **registry** of the relevant details in writing by no later than 5
business days before the last day of the month before the 1\textsuperscript{st} month for which the person requests the variation.

(6) The registry must comply with a request made in accordance with subclause (5) by 1000 hours on the 1\textsuperscript{st} business day of the calendar month following the calendar month in which the request was made.

11.31 Customer and embedded generator queries

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

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

Schedule 11.1

3 Electrically disconnecting De-energisation

Each ICP created after 7 October 2002 must be able to be electrically disconnected de-energised without electrically disconnecting de-energisation of another ICP, except for the following ICPs:

(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 difference between the total consumption for the embedded network and all other ICPs on the embedded network.

4 Authority may grant dispensation

The Authority may, by notification in writing, grant a dispensation from the requirements of clause 3 for an ICP that cannot be electrically disconnected de-energised without electrically disconnecting de-energisation of another ICP.

7 Distributors to provide ICP information to registry

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

…

(b) subject to subclause (4), the NSP identifier of the NSP to which the ICP is usually connected:

…

(f) if the ICP connects the distributor's network to an embedded generating station that has a capacity of 10 MW or more, the information required by subclause (6), in accordance with subclause (7):

…

(o) if the ICP connects the distributor’s network to distributed generation,—

(i) the nameplate capacity of the distributed generation; and
(ii) the generation fuel type of the **distributed generation**:

(p) the date on which the **ICP** is initially **energised-electrically connected**.

…

(2A) The **distributor** must provide the information specified in subclause (1)(p) to the **registry** no later than 10 **business days** after the date on which the **ICP** is initially **energised-electrically connected**.

(2B) Despite subclause (2A), the **distributor** is not required to provide the information specified in subclause (1)(p) if the date on which the **ICP** is initially **energised-electrically connected** is earlier than 29 August 2013.

…

(4) If a **distributor** cannot identify the **NSP** that is **connected** to an **ICP**, the **distributor** must nominate the **NSP** that the **distributor** thinks is most likely to be **connected** to the **ICP**, taking into account the flow of **electricity within the distributor’s network**.

(5) An **ICP** is deemed to be **connected** to the **NSP** nominated by the **distributor** under subclause (1)(b).

(6) If a **distributor** assigns a **loss category** code to an **ICP** on the **distributor’s network** that connects the **distributor’s network** to an **embedded generating station** that has a capacity of 10MW or more—

(a) the **loss category** code assigned to the **ICP** must be unique and must not be assigned to any other **ICP** on the **distributor’s network**; and

(b) the **distributor** must provide the following information to the **reconciliation manager**:

(i) the unique **loss category** code assigned to the **ICP**;

(ii) the **ICP identifier** of the **ICP**;

(iii) the **NSP identifier** of the **NSP** to which the **ICP** is **connected**;

(iv) the plant name of the **embedded generating station**.

8 **Distributors to change ICP information provided to registry**

(1) If information about an **ICP** provided to the **registry** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must notify the **registry** of the change.

(2) The **distributor** must give the notification—

(a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the **commissioning** or **decommissioning** of an **NSP**), no later than 8 **business days** after the change takes effect; and

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

(3) A **distributor** is not required to notify a change of information provided in accordance with clause 7(1)(b) if the change is for less than 14 days.

(4) If a change of information provided in accordance with clause 7(1)(b) is for more than 14 days, subclause (2) applies as if the change had taken effect on the 15th day after the change takes effect.
14 “Ready” status
(1) The ICP status of “Ready” must be managed by the relevant distributor and indicates that—
   (a) the associated electrical installations are ready for connecting to the electricity supply; or
   (b) the ICP is ready for activation by a trader.
(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.

15 "New" or "Ready" status for 24 calendar months or more
(1) Subclause (2) applies if—
   (a) an ICP has had the status of "New" for 24 calendar months or more; or
   (b) an ICP has had the status of "Ready" for 24 calendar months or more.
(2) The distributor must—
   (a) ask the trader who intends to trade at the ICP whether the ICP should continue to have that status; and
   (b) decommission the ICP if the trader advises that the ICP should not continue to have that status.

17 “Active” status
(1) The ICP status of “Active” must be managed by the relevant trader and indicates that—
   (a) the associated electrical installations are energised; 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.

19 “Inactive” status
The ICP status of “Inactive” must be managed by the relevant trader and indicates that—
   (a) the ICP is electrically disconnected; or
   (b) submission information related to the ICP is not required by the reconciliation manager for the purpose of compiling reconciliation information.

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 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.

25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network
(1) If an NSP is to be created or decommissioned, —
(a) the participant specified in subclause (3) in relation to the NSP must notify the reconciliation manager of the creation or decommissioning; and
(b) the reconciliation manager must notify the market administrator and affected reconciliation participants of the creation or decommissioning no later than 1 business day after receiving the notification in paragraph (a).

(2) If a distributor wishes to change the record in the registry of an ICP that is not recorded as being usually connected to an NSP in the distributor’s network, so that the ICP is recorded as being usually connected to an NSP in the distributor’s network (a "transfer"), the distributor must notify the reconciliation manager, the market administrator, and each affected reconciliation participant of the transfer.

(3) The notification required by subclause (1) must be given by—
(a) the grid owner, if—
   (i) the NSP is a point of connection between the grid and a local network; or
   (ii) if the NSP is a point of connection between a generator and the grid; or
(b) the distributor for the local network who initiated the creation or decommissioning, if the NSP is an interconnection point between 2 local networks; or
(c) the embedded network owner who initiated the creation or decommissioning, if the NSP is an interconnection point between 2 embedded networks; or
(d) the distributor for the embedded network, if the NSP is a point of connection between an embedded network and another network.

(4) A distributor who is required to notify a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

26 Information to be provided if NSPs are created or ICPs are transferred from 1 distributor's network to another distributor's network

... 

(2) The participant must make the request—
(a) in the case of a notification given under clause 25(3)(b) or (c), at least 10 business days before the NSP is electrically connected; and
(b) in every other case, at least 1 calendar month before the NSP is electrically connected or the ICP is transferred.

(3) If a participant gives a notification under clause 25(1) of the creation of an NSP, the distributor on whose network the NSP is located must give the reconciliation manager the following information:

... 

29 Obligations concerning change in network owner

(1) If a network owner acquires all or part of an existing network, the network owner must notify the following of the acquisition:
(a) the previous network owner:
(b) the reconciliation manager:
(c) the market administrator:
(d) every reconciliation participant who trades at an ICP connected to the network or part of the network acquired.
(2) The network owner must give the notification at least 1 calendar month before the acquisition.

(3) The notification must specify—
   (a) the ICP identifiers for which the network owner’s participant identifier must be amended to reflect the acquisition of the network or part of the network by the network owner; and
   (b) the effective date of the acquisition.

(4) A network owner who acquires all or part of an existing network must comply with Schedule 11.2.

30 Reconciliation manager to advise registry

(1) The reconciliation manager must—
   (a) advise the registry of any new or deleted NSP identifier no later than 1 business day after being notified of its creation or decommissioning; and

Schedule 11.2

1 This Schedule applies if a distributor (the applicant distributor) wishes to change the record in the registry of an ICP that is not recorded as being usually connected to an NSP in the distributor's network, so that the ICP is recorded as being usually connected to an NSP in the applicant distributor’s network (a "transfer").

5 The applicant distributor must give the market administrator confirmation that the applicant distributor has received written consent to the proposed transfer from—
   (a) the distributor whose network is associated with the NSP to which the ICP is recorded as being connected immediately before the notification, except if the notification relates to the creation of an embedded network; and
   (b) every trader who trades electricity at any ICP nominated at the time of notification as being supplied from the same NSP to which the notification relates.

Schedule 11.3

16 Gaining trader obligations

(1) The gaining trader must complete the switch by advising the registry of the event date no later than 3 business days after receiving a valid switch response code from the registry under clause 22(c).

(2) If the ICP is being electrically disconnected or if metering equipment is being removed, the gaining trader must either—
   (a) give the losing trader or the metering equipment provider for the ICP an opportunity to interrogate the metering installation immediately before the ICP is electrically disconnected or the metering equipment is removed; or
   (b) carry out an interrogation and, no later than 5 business days after the metering installation is electrically disconnected or removed, advise the losing trader of—
      (i) the results of the interrogation; and
(ii) the metering component numbers for each data channel in the metering installation.

Schedule 11.4

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

A metering equipment provider must advise the registry of the registry metering records, or any change to the registry metering records, for a metering installation for which it is responsible, no later than 10 business days following:
(a) the electrical connection of an ICP that is not also an NSP;
(b) any subsequent change in any matter covered by the metering records.

Part 12

12.17 Purpose of Connection Code

The purpose of the Connection Code is to set out the technical requirements and standards that designated transmission customers must meet in order to be connected to the grid and that Transpower must comply with. Transpower and designated transmission customers must comply with the Connection Code under default transmission agreements that apply under clauses 12.10 and 12.13.

12.20 Required content of Connection Code

The Connection Code must provide for the following matters:
(a) connection requirements for designated transmission customers:
(b) technical requirements for assets, including assets owned by Transpower, and for other equipment and plant that is connected to a local network or an embedded network or that forms part of an embedded generating station if the operation of that equipment and plant could affect the grid assets:
(c) operating standards for equipment that is owned by a designated transmission customer, used in connection with the conveyance of electricity, and that is situated on land owned by Transpower:
(d) information requirements to be met by designated transmission customers before equipment is connected to the grid and before changes are made to the equipment:
(e) an obligation on Transpower to provide a 10 year forecast of the expected maximum fault level of each point of service to designated transmission customers set out in the transmission agreement between Transpower and each designated transmission customer.

12.30 Principles for benchmark agreements

A benchmark agreement should—
(f) establish common standards for a common configuration based on factors such as size of connection and voltage level; and

(g) encourage efficient and effective processes for enforcement of obligations and dispute resolution.

12.31 Contents of benchmark agreements

(1) A benchmark agreement must include—

…

(b) an obligation on designated transmission customers to comply with Transpower’s reasonable technical connection and safety requirements; and

(c) an obligation on designated transmission customers to pay prices calculated in accordance with the transmission pricing methodology approved by the Authority under subpart 4; and

…

12.40 Replacement and enhancement of shared connection assets

(1) If 2 or more designated transmission customers are connected to a point of connection and Transpower has notified those designated transmission customers, in accordance with the provisions of a transmission agreement between Transpower and each of the designated transmission customers, that a grid reliability report published by Transpower in accordance with clause 12.76 sets out that the power system is not reasonably expected to meet the N-1 criterion at all times over the next 5 years because of a connection asset related to that point of connection, Transpower must—

…

12.41 Removal of shared connection assets from service

(1) If 2 or more designated transmission customers are connected to a point of connection, and Transpower is required by a transmission agreement between Transpower and each of those designated transmission customers to provide the connection assets at the point of connection, Transpower may permanently decommission a connection asset at that point of connection from service only—

(a) if the designated transmission customers unanimously agree with the permanent decommissioning and clauses 12.35 to 12.37 (if applicable) are complied with; or

(b) if the designated transmission customers do not unanimously agree, or none of the designated transmission customers agree, with the permanent decommissioning, if the permanent decommissioning results in a net benefit, as calculated under the test set out in clause 12.43.

(2) To avoid doubt, this clause applies only if Transpower proposes to remove a connection asset from service and not replace the asset with another connection asset.

12.42 Reconfiguration of shared connection assets

If 2 or more designated transmission customers are connected to a point of connection, and Transpower is required by a transmission agreement between Transpower and each of those designated transmission customers to provide the
connection assets in the configuration specified in each of those transmission agreements, Transpower may only change that configuration—

(a) if the designated transmission customers unanimously agree with the reconfiguration and clauses 12.35 to 12.37 (if applicable) are complied with; or
(b) if the designated transmission customers do not unanimously agree, or none of the designated transmission customers agree with the reconfiguration, if the reconfiguration results in a net benefit, as calculated under the test set out in clause 12.43.

12.49 Existing agreements

(1) Except as provided for by clause 12.95, this Part does not apply to or affect the rights, powers or obligations of a participant or Transpower under a written agreement entered into between that participant and Transpower for connection to and/or use of the grid that is—

(a) entered into before 29 October 2003; or
(b) based on Transpower’s standard connection contract and entered into before 28 June 2007.

(2) The exception from this Part in subclause (1) does not apply to a right, power or obligation of a participant that arises because of the variation of an agreement described in subclause (1).

(3) To avoid doubt, the posted terms and conditions of Transpower do not constitute a written agreement.

12.50 Copies of other agreements to be provided to Authority

(1) If requested to do so by the Authority, Transpower or a participant must provide a copy of any written agreement for connection to and/or use of the grid that Transpower or the participant is a party to and that was entered into before 28 June 2007.

(2) The copy that is provided must be—

(a) a copy of the complete agreement; and
(b) certified by a director or the chief executive of Transpower or the participant, to the best of the director’s or chief executive’s knowledge and belief, to be a true and complete copy of the agreement.

(3) An agreement must be published by the Authority, unless the parties establish to the satisfaction of the Authority that there is good reason for not publishing the agreement.

12.96 Development of transmission prices

After approval of the transmission pricing methodology, Transpower must—

(a) develop and publish transmission prices consistent with the transmission pricing methodology based on its total revenue requirement for connection to or use of the grid; and
(b) demonstrate to the Authority that the prices are consistent with the transmission pricing methodology.

12.112 Exceptions to clause 12.111

(1) Transpower is not required to comply with clause 12.111(1)(a) or (2) if—
(a) permitted under the Outage Protocol made under subpart 7; or
(b) an interconnection asset that forms part of an interconnection branch or the HVDC link, or a shunt asset—
   (i) is permanently removed from service, the grid is permanently reconfigured, or the transmission capacity of such an asset is reduced, and the decision to remove the asset from service or reconfigure the grid or reduce the transmission capacity of the asset takes into account the effect of the removal of the asset, reconfiguration of the grid, or the reduction in transmission capacity of the asset, on other materially affected parties, and is undertaken—
      (A) in order to maintain the health and safety of any person; or
      (B) in order to maintain the safety and integrity of equipment; or
      (C) in accordance with demonstrably prudent economic criteria; or
   (iaa) has been temporarily removed from service, or the grid has been temporarily reconfigured, in accordance with clause 12.116AA; or
   (ia) [Expired]
   (ii) has been permanently removed from service, or the grid has been permanently reconfigured, in accordance with clause 12.117; or
(c) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid, has been made as a result of an investment in the grid; or
(d) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid has been made as a result of an investment made under an investment contract entered into in accordance with clauses 12.70 and 12.71; or
(e) the voltage range specified in the AOPOs for an interconnection asset that forms part of an interconnection branch is modified, or any equivalence arrangement is approved or dispensation is granted under clauses 8.29 to 8.31 in respect of the asset; or
(ea) in relation to the HVDC link—
   (i) the HVDC owner is operating the HVDC link in accordance with—
      (A) a commissioning plan agreed with the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; or
      (B) a test plan provided to the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; and
   (ii) the configuration of the HVDC link is—
      (A) Pole 3 and Pole 2 bipole round power; or
      (B) Pole 3 and Pole 2 bipole not round power; or
(f) Transpower and a designated transmission customer have agreed otherwise in accordance with clause 12.128.

(2) If subclause (1)(c) to (e) apply, or the grid is reconfigured under subclause (1)(b)(i) or (ii), Transpower must—
   (a) make the interconnection branch, the HVDC link or the shunt asset available to the system operator at least at its modified capacity rating, and at its modified service levels; and
   (b) keep the grid in its modified configuration.

(2AA) Subclause (2AB) applies—
   (a) if subclause (1)(b)(iaa) applies; and
(b) while—
   (i) an interconnection asset that forms part of an interconnection branch or the HVDC link, or a shunt asset, has been temporarily removed; or
   (ii) the grid has been temporarily reconfigured.

(2AB) Transpower must make the interconnection branch, the HVDC link or the shunt asset available to the system operator at least at its modified capacity rating, and at its modified service levels.

(2A) [Expired]
(2B) [Expired]

(3) If a decision to remove an asset, or reconfigure the grid, or reduce the transmission capacity of an asset has been made under subclause (1)(b)(i) or (ii), Transpower must as soon as reasonably possible make publicly available the analysis it undertook in accordance with subclause (1)(b)(i) or (ii), or a summary of that analysis.

Schedule 12.1

1 Categories of designated transmission customers required to enter into transmission agreements with Transpower

(1) The categories of designated transmission customers required to enter into transmission agreements with Transpower are—
   (a) connected asset owners; and
   (b) [Revoked]
   (c) generators that are directly connected to the grid.

(2) [Revoked]
(3) [Revoked]
(4) [Revoked]
(5) [Revoked]

Part 12A

12A.7 Distributors must consult concerning changes to tariff structures

(1) This clause applies to each distributor who has 1 or more consumers connected to its network to whom the distributor does not send accounts for line function services directly.

(2) The distributor must consult with each trader trading on the distributor's network in respect of the distributor's tariff structure for the consumers referred to in subclause (1) before making a change to the tariff structure that materially affects 1 or more traders or consumers.

(3) For the purpose of subclause (2), changes to a distributor's tariff structure that may materially affect 1 or more traders or consumers include, but are not limited to, any of the following:
   (a) a change by the distributor to the eligibility criteria for 1 or more of the distributor's tariff rates:
   (b) a change by the distributor to the distributor's tariff structure by the introduction of a new tariff rate:
(c) a change by the distributor to the distributor's tariff structure that means that 1 or more of the distributor's tariff rates are no longer available.

(4) However, the fact that a change is listed in subclause (3) does not mean that a distributor is required to consult on the change if the change will not materially affect traders or consumers.

(5) [Revoked]

12A.11 Application of clauses 12A.12 to 12A.14
Clauses 12A.12 to 12A.14 apply to —
(a) a distributor who has 1 or more consumers connected to its network to whom the distributor does not send accounts for line function services directly; and
(b) a trader trading on the network of the distributor described in paragraph (a).

Part 13

13.6 Generators
(1) Each generator (other than an embedded generator submitting an offer in accordance with subclause (2) or an intermittent generator submitting an offer in accordance with subclause (3)) must—
(a) submit to the system operator an offer—
(i) for each trading period in the schedule period; and
(ii) 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 applies.

(2) Despite subclause (1), each embedded generator required by the system operator to provide an offer in accordance with clause 8.25(5) (other than an embedded generator who is also an intermittent generator submitting an offer in accordance with subclause (3)), must—
(a) submit to the system operator an offer—
(i) for each trading period of the schedule period; and
(ii) under which the generator is intending to generate electricity; and
(b) ensure that the system operator receives the offer at least 71 trading periods before the beginning of the trading period to which the offer applies.

(3) Despite subclauses (1) and (2), each intermittent generator with a point of connection to the grid, and each intermittent generator with a point of connection to a local network, required by the system operator to provide an offer under clause 8.25(5), must—
(a) submit to the system operator an offer—
(i) for each trading period of the schedule period; and
(ii) which is based on the intermittent generator’s forecast of the electricity that it expects to be able to generate; and
(b) ensure that the system operator receives the offer at least 71 trading periods before the beginning of the trading period to which the offer applies.
(4) Despite subclauses (1) to (3), a generator must give not less than 5 business days’ notice in writing to the system operator and the pricing manager before the generator makes an offer for the 1st time in respect of a generating plant. The notice must include advice as to which grid injection point the generating plant is connected to and whether the generating plant is an intermittent generating station. The generator must comply with any request the system operator may make for information concerning the generating plant that the system operator may reasonably require for the purposes of scheduling and dispatch in accordance with this Code.

13.27J New GXP

At least 1 calendar month before a grid owner connects a GXP to the grid for the first time, the grid owner must advise the Authority in writing of its intention to connect the GXP.

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.

(2) The data provided under subclause (1) must include—
(a) the HVDC transmission lines and system capacity, including reserve capacity; and
(b) HVDC link capacity, including limits of each HVDC transmission line of the HVDC transmission system; and
(c) HVDC system loss characteristics including transmission loss functions for each transmission line of the HVDC transmission system; and
(d) in relation to Pole 2, or Pole 3, or Pole 2 and Pole 3, of the HVDC link—
   (i) if the HVDC owner imposes a limit on transfer direction, the direction of that transfer limit (northward or southward); and
   (ii) if the HVDC owner imposes a minimum transfer limit, that minimum transfer limit (in MW); and
   (iii) if the HVDC owner imposes a maximum transfer limit, that maximum transfer limit (in MW).

(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 is—
   (i) Pole 3 and Pole 2 bipole round power; or
   (ii) Pole 3 and Pole 2 bipole not round power.

13.40 Inter-relationship between reserve offers of interruptible load and bids

Bids and reserve offers of interruptible load are inter-related in that the disconnection of demand electrically disconnected in response to an under-frequency event and in accordance with a dispatched reserve offer may lower the quantity purchased at that grid.
exit point. Accordingly, a purchaser does not breach the reasonable estimate requirement in clauses 13.7(3), 13.7AA(2), and 13.8A(4) if the purchaser is acting as an ancillary service agent and electrically disconnects corresponding demand in response to an under-frequency event in accordance with a dispatched reserve offer.

13.80 Dispatch instructions provided to grid owner

(1) If the system operator has issued a dispatch instruction to an embedded generator to generate from a generating plant required by the system operator to be scheduled, the system operator must inform the grid owner that is connected to the local network in which the embedded generator is located of the quantity of active power that was the subject of such dispatch instruction and the trading periods for which the dispatch instruction was issued.

(2) The system operator must provide the information to the relevant grid owner by 0400 hours on the day after the dispatch instruction was issued.

13.82 Dispatch instructions to be complied with

(1) This clause applies to—
(a) a generator; and
(b) an ancillary service agent; and
(c) a dispatched purchaser.

(2) Each participant to which this clause applies must comply with a dispatch instruction properly issued by the system operator under clause 13.72 unless,—
(a) in the participant's reasonable opinion,—
(i) personnel or plant safety is at risk; or
(ii) following the dispatch instruction will contravene a law; or
(b) the generating plant or dispatch-capable load station is already responding to an automated signal to activate—
(i) capacity reserve; or
(ii) instantaneous reserve; or
(iii) automatic under-frequency load shedding; or
(iv) over frequency reserve; or
(c) the participant is a generator or ancillary service agent acting in accordance with clause 13.86; or
(d) the participant is an intermittent generator that has complied with clause 13.17, and the system operator has not advised that there is—
(i) a grid emergency; or
(ii) a system constraint that directly affects the intermittent generator; or
(e) the participant—
(i) is a generator; and
(ii) deviates from a dispatch instruction for active power to comply with clause 8.17; or
(f) the participant—
(i) is a dispatched purchaser; and
(ii) deviates from the dispatch instruction—
(A) to comply with a request issued by the system operator under clause 5(4) of Technical Code B of Schedule 8.3; or
(B) to comply with clause 8.18; or
(g) the participant—
(i) is a dispatched purchaser; and
(ii) cannot comply with the dispatch instruction because of a disconnection of demand has been electrically disconnected under clause 7A of Technical Code B of Schedule 8.3; or

(ga) the participant—
(i) is a dispatched purchaser; and
(ii) the dispatch instruction is issued for a trading period for which the latest nominated bid for the relevant dispatch-capable load station is a nominated non-dispatch bid; or

(h) the participant—
(i) is a generator or an ancillary service agent; and
(ii) deviates from a dispatch instruction to comply with clause 9 of Technical Code B of Schedule 8.3; or

(i) the participant—
(i) is a generator or an ancillary service agent; and
(ii) is acting in accordance with a commissioning plan or test plan that—
(A) is required under clause 2(6) of Technical Code A of Schedule 8.3; and
(B) expressly allows the generator or ancillary service agent to depart from the dispatch instruction for the purpose of the commissioning plan or test plan; and
(iii) has no reasonable means of complying with the dispatch instruction while acting in accordance with the commissioning plan or test plan; or

(j) the participant is a type B co-generator and the system operator has not advised that there is—
(i) a grid emergency; or
(ii) a system constraint that directly affects the type B co-generator.

A participant to which the exception in subclause (2)(a) applies must immediately advise the system operator of the circumstance in which the exception arises.

If a dispatched purchaser is issued with more than 1 dispatch instruction for the same dispatch-capable load station for the same trading period, the dispatched purchaser must comply with the latest dispatch instruction.

To avoid doubt, a dispatch instruction listed in clause 13.73(1)(b) to 13.73(1)(f) or 13.73(1)(h) is properly issued only if—
(a) the generator or ancillary service agent to which the dispatch instruction is given has an enforceable contract with the system operator for the provision of services relating to the dispatch instruction; or
(b) the dispatch instruction is consistent with an enforceable contract between the system operator and the generator or ancillary service agent for the provision of services relating to the dispatch instruction; or
(c) the dispatch instruction is given for the purposes of clause 8.5 or 13.70; or
(d) the dispatch instruction is consistent with—
(i) the asset owner performance obligations under clauses 8.22 to 8.24; or
(ii) the technical codes concerning voltage; or
(iii) a dispensation.

A dispatched purchaser issued with a dispatch instruction for a dispatch-capable load station must not make changes to its other load at the same GXP with the intention of offsetting the dispatch instruction for the dispatch-capable load station.

221
13.104 Information to be published
(1) As soon as practicable after the system operator has completed preparing a price-responsive schedule and a non-response schedule, the system operator must publish, for each trading period in the schedule length period,—
(a) the following information in respect of both the price-responsive schedule and the non-response schedule:

   ... (iv) the grid injection points and grid exit points that are disconnected have no load or generation connected to them in the modelling system;

13.136 Generators to provide half-hour metering information
(1) Each generator must give the relevant grid owner half-hour metering information under clause 13.138 in relation to generating plant that is subject to a dispatch instruction—
   (a) that injects electricity directly into a local network or an embedded network; or
   (b) if the meter configuration is such that the electricity flows into a local network without first passing through a grid injection point or grid exit point metering installation.

   (1A) For the purposes of subclause (1), the relevant grid owner is—
   (a) in relation to a generator (other than an embedded generator), the grid owner of the grid to which the generator's generation is connected; and
   (b) in relation to a generator that is an embedded generator, the grid owner of the grid to which the local network to which the embedded generator is directly or indirectly connected, is connected.

(2) To avoid doubt, subclause (1) does not apply in respect of—
   (a) any unoffered generation; or
   (b) electricity supplied from—
      (i) an intermittent generating station; or
      (ii) a type B industrial co-generating station.

13.194 Clearing manager to calculate constrained off amounts
(2) For the purposes of clauses 13.192 to 13.201, dispatched quantity must be calculated taking into account—
   (a) the quantity in MW recorded in the log kept by the system operator in accordance with clause 13.76 and, if required, the clearing manager must aggregate such quantities for—
      (i) generating stations or generating units in the relevant station dispatch group; or
      (ii) generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis; and
   (b) for an offer, the ramp rate applying to that constrained off situation that is specified in the offer submitted by that generator, or—
      (i) for a block dispatch group or a station dispatch group; or
(ii) for generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis—
the fastest of the ramp rates applying to that constrained off situation that are specified in the offers submitted by the generator in that block dispatch group, that station dispatch group or those generation units electrically connected to the relevant grid injection point (as the case may be); and

...  

13.204 Calculation of constrained on amounts
(1) If a constrained on situation occurs during any trading period during a previous billing period,—

...  

(b) for the purposes of clauses 13.202 to 13.211 dispatched quantity must be calculated taking into account—

...  

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

(A) for a block dispatch group or a station dispatch group; or

(B) for generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis—
the fastest of the ramp rates applying to that constrained on situation that are specified in the offers submitted by the generator in that block dispatch group, that station dispatch group or those generating units electrically connected to the relevant grid injection point (as the case may be); and

...  

Schedule 13.3

11 Constraints relating to transmission system
The final schedule provided by the modelling system must have the following characteristics (all of which must be met to an accuracy to be specified in the model formulation):

(a) the total scheduled flow into and out of a grid injection point or grid exit point must equal 0 for all grid injection points and grid exit points:

(b) the modelling system must calculate losses in transmission lines, the HVDC link, and transformers. Those losses must be approximated using the information provided by grid owners under clauses 13.29 to 13.31, for transmission lines, the HVDC link and transformers respectively:

(c) the modelling system must calculate the electricity flows into individual transmission lines and flows into the connection connection points of transformers connected connected at the same grid injection point or grid exit point using an established DC power flow technique within the limitations imposed by the technique that—

(i) correctly adjusts flows for transmission system losses; and

(ii) correctly apportions flows in transmission system loops, whether or not those loops contain transmission constraints—

223
provided that the capacity of transformers through which electricity is supplied to a grid exit point is not included in the model unless the transformer may carry flows of electricity other than offtakes from that grid exit point.

16 Calculation of prices, marginal location factors and reserve prices

... (2) The modelling system must assign a 0 price for electricity at each grid injection point and grid exit point that is disconnected has no load or generation connected to it in the modelling system.

Part 14

14.44 Event of default gives clearing manager remedies

(1) If an event of default has occurred, the clearing manager has the power to exercise, as appropriate, all or any of the following remedies without prejudice to any other remedy it may have at law:
   (a) apply the balance of the cash deposit of the defaulting participant in accordance with clause 14A.13(a);
   (b) make a demand under a guarantee, letter of credit, or bond provided under Part 14A in respect of the defaulting participant;
   (c) if the defaulting participant has not paid an amount due under this Part by the due date for payment, set-off any amount payable by the clearing manager to the defaulting participant against the unpaid amount payable by the defaulting participant to the clearing manager;
   (d) take possession of any FTR held by the defaulting participant in accordance with clause 14.47.

(2) If an event of default is continuing at the expiry of the participant's post-default exit period registered under clause 14A.22,—
   (a) the clearing manager must cancel a hedge settlement agreement to which the defaulting participant is a party in accordance with clause 14.48;
   (b) the Authority may direct a grid owner or distributor to exercise any contractual right the grid owner or distributor has to electrically disconnect disconnect a defaulting participant that is a direct purchaser in accordance with clause 14.49.

14.49 Electrical disconnection of direct purchaser

(1) Each direct purchaser must at all times ensure that the terms of each of its contracts that provide for the connection of the direct purchaser to a network permit the relevant grid owner or distributor to electrically disconnect disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

(2) Each grid owner or distributor must at all times ensure that the terms of each of its contracts that provide for the connection of a direct purchaser to a network permit the grid owner or distributor to electrically disconnect disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser.
purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

(3) If an event of default occurs in relation to a direct purchaser and is continuing at the expiry of the direct purchaser's post-default exit period registered under clause 14A.22, the Authority may direct a grid owner or distributor to exercise any contractual right the grid owner or distributor has to electrically disconnect disconnect the defaulting direct purchaser.

(4) A grid owner or distributor that receives a direction under subclause (3) must comply with the direction.

Schedule 14.3

2 Interpretation
(1) In this Schedule, unless the context otherwise requires,—

closed, in relation to a branch, means that the branch is electrically connected connected at both ends

open, in relation to a branch, means that the branch is electrically disconnected disconnected at 1 or both ends

4 Grid owner must determine normal grid configuration
(1) Each grid owner must determine a normal grid configuration for the grid owner’s grid.
(2) The normal grid configuration determined under subclause (1) must be a grid configuration with all existing branches and switches closed except where the grid owner has implemented operational system splits and the grid owner considers that the normal state of those operational system splits is for the relevant branch or switch to be open.
(3) Each grid owner must provide to the FTR manager the information describing the normal grid configuration for the grid owner’s grid determined under subclause (1).
(4) Each grid owner must determine a new normal grid configuration for the grid owner’s grid if the grid owner considers it necessary because, for example, any of the following occur:
   (a) some grid equipment is commissioned commissioned or decommissioned decommissioned;
   (b) there is a change in the capacity or impedance of some grid equipment;
   (c) the grid owner considers that the normal state of any operational system split has changed.
(5) Each grid owner must provide new information to the FTR manager if the grid owner determines a new normal grid configuration for the grid owner’s grid under subclause (4), unless otherwise agreed with the FTR manager.

9 FTR manager must calculate amounts to be applied to settlement of FTRs
(1) The amounts calculated under this clause must be calculated using the flow quantities, nodal prices and shadow prices from the final pricing schedule.
(2) The HVDC loss and constraint excess to be applied to the settlement of FTRs for each trading period of the relevant billing period must be calculated in accordance with the following formula:

\[
\max \left\{ 0, \sum_{n \in n(NI)} \frac{\sum_{l \in S_{HVDC} | n} (HVDCLinkFlow_l - HVDCLinkLosses_l) - \sum_{l \in S_{HVDC} | n} HVDCLinkFlow_l}{\sum_{l \in S_{HVDC} | n} \sum_{j \in S_{HVDC} | n} (HVDCLinkFlow_{ij} - HVDCLinkLosses_{ij}) - \sum_{l \in S_{HVDC} | n} HVDCLinkFlow_l} \times \sum_{n \in n(SI)} \frac{\sum_{l \in S_{HVDC} | n} (HVDCLinkFlow_l - HVDCLinkLosses_l) - \sum_{l \in S_{HVDC} | n} HVDCLinkFlow_l}{\sum_{l \in S_{HVDC} | n} \sum_{j \in S_{HVDC} | n} (HVDCLinkFlow_{ij} - HVDCLinkLosses_{ij}) - \sum_{l \in S_{HVDC} | n} HVDCLinkFlow_l} \right\} \div 2
\]

where

- \(price_n\) is the energy price at AC node \(n\)
- \(n(NI)\) is the set of North Island AC nodes to which any HVDC links are connected
- \(n(SI)\) is the set of South Island AC nodes to which any HVDC links are connected
- \(HVDCLinkFlow_l\) is the MW flow at the sending end scheduled for HVDC link \(l\)
- \(HVDCLinkLosses_l\) is the variable MW losses for HVDC link \(l\)
- \(S_{HVDC}(n)\) is the set of HVDC links for which \(n\) is the sending AC node
- \(R_{HVDC}(n)\) is the set of HVDC links for which \(n\) is the receiving AC node
Part 15

15.5B Deriving volume information if metering installation is within premises that are connected to a point of connection

(1) This clause applies if a dispatch-capable load station’s metering installation is not at a point of connection but is located within premises that are directly connected to a point of connection.

(2) If this clause applies, the dispatchable load purchaser responsible for the dispatch-capable load station must prepare dispatchable load information using volume information prepared in accordance with Schedule 15.2 and derived from the raw meter data—
   (a) obtained from the metering installation; and
   (b) that the dispatchable load purchaser has adjusted, using an accurate compensation factor, to compensate for internal site losses between the metering installation and—
      (i) if the premises are directly connected to a point of connection to the grid, the point of connection to the grid; or
      (ii) if the premises are directly connected to a point of connection to a local network, the point of connection to the local network; or
      (iii) if the premises are directly connected to a point of connection to an embedded network, the point of connection to the embedded network.

(3) For the purpose of this clause, a dispatchable load purchaser must have a certified metering installation for each of its dispatch-capable load stations.

15.14 Notification of changes to the grid

(1) Each grid owner must notify the reconciliation manager, in accordance with any procedures or other requirements reasonably specified by the reconciliation manager from time to time, of any changes that the grid owner intends to make to the grid that will affect reconciliation.

(2) The grid owner must give the notice at least 1 calendar month before the effective date of the intended change.

(3) No later than 1 business day after receipt of the notice, the reconciliation manager must give a copy of the notice to the clearing manager and the Authority.

(4) Each grid owner must give notice of an intended change to an existing point of connection to the grid or a new point of connection to the grid to be commissioned.

15.15 Notification of points of connection subject to outages or alternative supply

No later than 2 hours after publication of final prices for all trading periods in a consumption period,—
   (a) the system operator must notify the reconciliation manager of the following:
      (i) each point of connection to the grid that was disconnected had no load or generation connected to it in the modelling system in the consumption period;
      (ii) in relation to each point of connection referred to in subparagraph (i), the trading periods in the consumption period during which the point of connection to the grid was disconnected had no load or generation connected to it in the modelling system; and
15.22 Providing information to reconciliation participants

The reconciliation manager must provide to a reconciliation participant the information it has concerning the quantity of electricity conveyed at an NSP for each consumption period, by a time agreed between the reconciliation participant and the reconciliation manager (or if no such time can be agreed, by such time as determined by the Authority), if—

(a) the reconciliation participant has requested the information; and
(b) the reconciliation participant has purchased or sold electricity at the NSP during the consumption period or, in the case of a network owner, has a liability as a transporter of electricity in relation to the NSP; and
(c) the reconciliation participant meets the reconciliation manager’s reasonable costs of providing the information; and
(d) the reconciliation participant ensures that all information received in accordance with this clause is kept and maintained confidential to the employees of the reconciliation participant who are required to have access to the information to enable the reconciliation participant to identify errors in the reconciliation information produced for the NSP; and
(e) the reconciliation participant ensures that all information received in accordance with this clause is not used for any purpose other than enabling the reconciliation participant to identify errors in the submission information submitted for the NSP or, in the case of any network owner, other than for a legitimate purpose directly connected with the network owner’s liability as a transporter of electricity in relation to that NSP; and
(f) the reconciliation participant implements and maintains best practice internal procedures to meet its obligations in accordance with this clause.

Schedule 15.2

5 Non half-hour metering information

A reconciliation participant must, when manually interrogating a non half-hour metering installation, if the relevant parts of the metering installation are visible and it is safe to do so,—

(a) obtain the meter register value; and
(b) ensure seals are present and intact; and
(c) check for phase failure if the meter supports it; and
(d) check for signs of tampering or damage; and
(e) check for electrically unsafe situations where electrically unsafe has the meaning given to it in the Electricity (Safety) Regulations 2010.

Schedule 15.4

16 Calculation of unaccounted for electricity
(1) The **reconciliation manager** must calculate the **unaccounted for electricity** for each **balancing area** for each **trading period** in accordance with the following formula after all relevant quantities have been loss adjusted and scaled for **ICP days**:

\[
UFE_{BA} = TOT_{BA} - Q_{BA-EN}
\]

where

- **UFEBA** is the **unaccounted for electricity** for each **balancing area** for the relevant **trading period**
- **TOTBA** is the net total of all **electricity** injected into the **balancing area** less all **electricity** leaving the **balancing area** as measured at—
  - (a) the **NSPs** in respect of the **balancing area**; and
  - (b) the **ICPs** for any **embedded generators electrically connected** to the **balancing area**
- **QBA-EN** is all **electricity** conveyed to **consumers connected** connected to the **balancing area**, being the sum of the consumption parts of **submission information**, adjusted for **losses** and **ICP days**.

(2) The **reconciliation manager** must calculate the **UFE** factor in respect of each **balancing area** for each **trading period** as follows:

\[
UFE \text{ Factor}_{BA} = \frac{TOT_{BA}}{Q_{ICPD-LA}}
\]

where

- **UFE FactorBA** is the **unaccounted for electricity** factor in respect of each **balancing area** for each **trading period**
- **QICPD-LA** is all **electricity** conveyed to **consumers and embedded networks connected** connected to the **balancing area**, being the sum of the consumption parts of **submission information**, adjusted for **losses** and **ICP days**
- **TOTBA** has the meaning given to it in subclause (1).

**21 Parent network UFE allocated to embedded networks**
A portion of the **UFE** from the **balancing area** to which an **embedded network** is **connected** must be allocated by the **reconciliation manager** to each **reconciliation participant** trading on the **embedded network**. The quantity of **UFE** to be allocated by the **reconciliation manager** to the **embedded network** must be allocated in proportion to the ratio of the **embedded network**’s, and upstream **balancing area**’s, **submission information** quantities (that have been adjusted for **losses** and **ICP days**).

**27 Surveillance reports**
The **reconciliation manager** must make the following reports available to the **Authority** and all participants:
(a) reports by retailers and direct purchasers for the total un accounted for electricity for each NSP:
(b) reports by retailers for each balancing area of the variation between electricity supplied as reported by retailers (in accordance with clause 17) and submission information submitted for reconciliation by retailers:
(c) summary reports of all half hour metered connections for which submission information has not been received within the time required by this Code:
(d) summary reports by retailers and direct purchasers separately for non half hour and half hour, of all ICP days for which reconciliation information has not been received within the time required by this Code:
(e) reports for each balancing area for the difference between the daily average non half hour kWh submitted by each retailer and direct purchaser per NSP, and the daily average non half hour kWh submitted by all retailers and direct purchasers per NSP:
(f) separate reports for non half hour and half hour submission information detailing the difference between the quantity of electricity in initial and the quantity of electricity in each subsequent submission information submission for each NSP and each retailer and direct purchaser.

Schedule 15.5

15 Determine total balancing area load
(1) This calculation determines the total electricity consumption inside a balancing area by summing all of the injection into a balancing area and subtracting the extraction out of the balancing area. In this case, injection is defined as electricity entering (Ei) the balancing area and includes flows from embedded generators, or any other network (including embedded networks or the grid). Similarly, extraction is defined as the flows of electricity leaving (Li) the balancing area, to other networks.

\[
\text{TOTBA} = (E_{GD} + E_{LN} + E_{EN}) - (L_{GD} + L_{LN} + L_{EN}) + (E_{EG})
\]

where

\[
\text{TOTBA}
\]

is the total quantity of electricity consumed within the balancing area, measured as being the sum of flows injected into the balancing area less flows out to any embedded network or to another electrically connected network.
\[ E_{GD} \] is the quantity of electricity entering the \textit{balancing area}, as measured by the \textit{grid NSP metering installation} for the \textit{balancing area}

\[ E_{LN} \] is the quantity of electricity, entering the \textit{balancing area} through an \textit{interconnection point} from another \textit{network}, as measured by the \textit{NSP metering installation} (which has been adjusted for \textit{losses})

\[ L_{GD} \] is the quantity of electricity leaving the \textit{balancing area}, as measured by the \textit{grid NSP metering installation} for the \textit{balancing area}

\[ E_{EN} \] is the quantity of electricity entering the \textit{balancing area} from an \textit{embedded network}, as measured by the \textit{NSP gateway metering installation} for the \textit{embedded network}

\[ E_{EG} \] is the quantity of electricity entering the \textit{balancing area} from an \textit{embedded generator electrically connected} to the \textit{network}, (which may either be \textit{half hour} or \textit{non half hour} metered), as measured by the \textit{NSP metering installation}

\[ L_{LN} \] is the quantity of electricity, leaving the \textit{balancing area} through an \textit{interconnection point} to another \textit{network}, as measured by the \textit{NSP metering installation} (which has been adjusted for \textit{losses})

\[ L_{EN} \] is the quantity of electricity, leaving the \textit{balancing area} to an \textit{embedded network}, as measured by the \textit{NSP gateway metering installation} for the \textit{embedded network}.

\textit{Schedule 15.5, Appendix 1}

3 \textbf{Profile class 1.2 separately metered controlled load}

1. \textbf{Meters} in the \textit{profile class} 1.2 separately metered controlled load classification include a separate \textit{meter} for a ripple controlled water heater, which may be switched on and off at variable times of the day. The entire load recorded on this register must be available for control.

2. Information from the operation logs of equipment controlling the \textit{connection} of controllable loads must be used to determine the time period relating to them. If the controllable load component is not static, a calculation of the diversity of the load must be documented and applied.

3. Other \textit{meters} in the \textit{metering installation} must be applied as per \textit{profile class} 1.1 or 1.4, as appropriate.
CRP 2016-13 and CRP 2016-14: Simplifying how information is published, and how the information system is defined.

Part 1

approved system means the system or systems required to convey information between persons in accordance with this Code as may be approved from time to time by the Authority

base case means a base case published by the Authority under clause 13.236D

collection and operation standards, in relation to a distributor or distributed generation,—

(a) means requirements, as amended from time to time by the distributor, that—

(i) are set out in written policies and standards of the distributor; and

(ii) relate to the connection of distributed generation and the operation of the distribution network, including requirements relating to the planning, design, construction, testing, inspection, and operation of assets that are, or are proposed to be, connected; and

(iii) are made publicly-available in accordance with clause 6.3; and

(iv) reflect, or are consistent with, reasonable and prudent operating practice; and

(b) includes the following, as amended from time to time by the distributor:

(i) the distributor's congestion management policy, as referred to in clause 6.3(2)(d); and

(ii) the distributor's emergency response policies; and

(iii) the distributor's safety standards

disclosure information, in relation to a participant, means information that—

(a) is about the participant; and

(b) is held by the participant; and

(c) the participant expects, or ought reasonably to expect, if published or otherwise made available to the public, will have a material impact on prices in the wholesale market

information system means the system or systems required for the conveyance of information between persons in accordance with this Code as may be approved from time to time by the Authority

publicise means to make available to the public, at no cost to the public,—

(a) on the Authority’s website at all reasonable times; and

(b) in any other manner that the Authority may decide

publish means—

(a) in respect of information to be published by the Authority, to make the information available to the public, at no cost, on a website maintained by or on behalf of the Authority; or
(b) in respect of information to be published by a participant, to make the information available to the public, at no cost, on a website maintained by or on behalf of the participant, and published, publishes, publication, and publishing have corresponding meanings

(a) in respect of information to be published by the Authority or a market operation service provider, to make such information available to the intended recipient through the information system; and

(b) in respect of a document to be published under Part 9,—

(i) to make the document available to the public, at no cost, on an internet site maintained by or on behalf of the system operator, at all reasonable times, and

(ii) to give notice in the Gazette of the document, of the fact that it is available on the Internet at no cost, and of the Internet site address; and

(c) in respect of all other information, to make available to the intended recipient in such manner as may be prescribed from time to time by the Authority,—

and published, publishes, publication, publisher and publishing have corresponding meanings

republish means to publish again following a recalculation using revised data, and republished and republication have corresponding meanings

stress test means a stress test publishedpublicised by the Authority under clause 13.236D

system operator register means the register kept by the system operator for recording equivalence arrangements, dispensations, and alternative ancillary service arrangements in accordance with clause 8 of Schedule 8.1 and clause 4 of Schedule 8.2. The system operator must maintain an up to date copy of the system operator register and publish it and keep it published make it available to registered participants at no cost on the system operator’s website at all reasonable times

WITS means the system operated by the WITS manager

Part 2

2.7 Other reasons

A participant may also refuse to supply Code information if—

(a) the information requested is, or will soon be, publishedpublicly available; or

(b) the information requested does not exist or cannot be found; or

(c) the information requested cannot be made available without substantial collation or research and the Authority agrees that it is unreasonable to undertake the collation or research; or

(d) the request is frivolous or vexatious or the information requested is trivial.

Part 3

3.5 Publication of market operation service provider agreements

The Authority must publishpublicise each market operation service provider agreement.

3.7 Relief of obligation because of force majeure
(5) The Authority must publish the information provided under subclause (2)(a) and the reports provided under subclauses (3) and (4) as soon as practicable after receiving the information.

(6) Despite subclause (5), the Authority must not publish or otherwise make publicly available to the public any information or any part of a report if the market operation service provider advises the Authority (with reasons) that the market operation service provider considers that it would have good reason to refuse to supply the information or the part under clause 2.6 or clause 2.7.

Part 4

4.1 Relief of obligation because of force majeure

(6) The Authority must publish the information provided under subclause (2)(a) and the reports provided under subclauses (4) and (5) as soon as practicable after receiving the information.

(7) Despite subclause (6), the Authority must not publish or otherwise make publicly available to the public any information or any part of a report if the ancillary service agent advises the Authority (with reasons) that the ancillary service agent considers that it would have good reason to refuse to supply the information or the part under clause 2.6 or clause 2.7.

Part 6

6.7 Extra terms

(1) The parties' rights and obligations in respect of a connection on the regulated terms are also governed by any other terms and conditions that—

(a) were made publicly available under clause 6.3(d) in a statement of the terms and conditions that would apply to distributed generation if there is congestion on the distribution network; or

(b) cover any other incidental matters (for example, invoicing procedures) if—

(i) the matters are not covered by the regulated terms; and

(ii) the other matters are reasonable terms and conditions that either were proposed by the distributor during the 30 business day negotiation period as part of a connection contract or are terms that would be implied by law if the connection was under a connection contract; and

(iii) the other terms and conditions do not contradict any of the regulated terms.

(2) In this Part, if the parties have agreed to change all or any part of 1 or more of the regulated terms as part of a binding contract, the resulting contract is, in total, a connection contract on terms that apply instead of the regulated terms for the purposes of this Part.

Schedule 6.1

2 Applications under this Part of this Schedule

(1) [Revoked]
(2) A **distributed generator** must apply to a **distributor** by—
(a) using the application form provided by the **distributor** that is publicly available under clause 6.3(2)(a); and
(b) providing any information in respect of the **distributed generation** to which the application relates that is—
   (i) referred to in subclause (3); and
   (ii) specified by the **distributor** under clause 6.3(3) as being required to be provided with the application; and
(c) paying the application fee (if any) specified by the **distributor** in accordance with clause 6.3(2)(e).

9B Application for distributed generation of 10 kW or less in total in specified circumstances
(1) A **distributed generator**'s application to a **distributor** must specify which of the following circumstances applies:
(a) the **distributed generator** wishes to **connect distributed generation**;
(b) the **distributed generator** wishes to continue an existing **connection** of **distributed generation** that is **connected** in accordance with a **connection contract** that—
   (i) is in force and the **distributed generator** wishes to extend the term of the **connection contract**; or
   (ii) has expired;
(c) the **distributed generator** wishes to continue an existing **connection** of **distributed generation** that is **connected** without a **connection contract**;
(d) the **distributed generator** wishes to change the **nameplate capacity** or fuel type of **connected distributed generation**.

(2) An application must include the following:
(a) the name, contact, and address details of the **distributed generator** and, if applicable, the **distributed generator’s agent**;
(b) a brief description of the physical location at the address at which the **distributed generation** is or will be **connected**;
(c) any application fee specified by the **distributor** in accordance with clause 6.3(2)(e);
(d) details of the make and model of the inverter;
(e) confirmation as to whether the inverter—
   (i) is included on the **distributor’s list of approved inverters** made publicly available under clause 6.3(2)(f); or
   (ii) conforms with the protection settings specified in the **distributor’s connection and operation standards**;
(f) if the inverter is not included on the **distributor’s list of approved inverters**, a copy of the AS 4777.2 Declaration of Conformity certificate for the inverter;
(g) details of—
   (i) the **nameplate capacity** of the **distributed generation**; and
   (ii) the fuel type of the **distributed generation** (for example, solar, wind, or liquid fuel).

....
11 Distributed generator must make initial application and give information

(1) [Revoked]

(2) A distributed generator must apply to a distributor ("initial application") by—

(a) using the application form provided by the distributor that is publicly available under clause 6.3(2)(a); and

(b) providing any information in respect of the distributed generation to which the application relates that is—

(i) referred to in subclause (3); and

(ii) specified by the distributor under clause 6.3(3) as being required to be provided with the application; and

(c) paying the application fee (if any) specified by the distributor in accordance with clause 6.3(2)(e).

15 Distributed generator must make final application

(1) A distributed generator that makes an initial application to a distributor must make a final application, no later than 12 months after receiving information under clauses 12 and 13, if the distributed generator wishes to proceed with the application, unless—

(a) the distributor and the distributed generator agree that a final application is not required; and

(b) there are no persons to whom notification is required under clause 16 at the time that the distributor and distributed generator agree that a final application is not required.

(1A) If a final application is not required—

(a) subclause (2) does not apply; and

(b) the distributed generator’s initial application must be treated as a final application for the purposes of clauses 16 to 24.

(2) The distributed generator must make the final application by—

(a) using the final application form provided by the distributor that is publicly available under clause 6.3(2)(a); and

(b) providing the results of any investigative studies that were identified by the distributor under clause 12(e)(i) as to be undertaken by the distributed generator or the distributed generator’s agent.

Part 7

7.3 Functions of the system operator in relation to security of supply and emergency management

...
(a) the system operator considers that there are good reasons to use different assumptions; and
(b) the system operator includes in the security of supply assessment—
   (i) a detailed explanation of the assumptions used to prepare the security of supply assessment; and
   (ii) a statement of reasons for using those assumptions instead of the assumptions published by the Authority; and
   (iii) a description of how the security of supply assessment prepared using those assumptions differs from a security of supply assessment prepared using the assumptions set out in the security standards assumptions document.

7.8 Review of system operator

...  
(3) The Authority must publish a report on the performance of the system operator no later than 10 business days after the Authority completes its review.

7.12 Authority must publish system operator reports

(1) The Authority must publish all self-review reports that are received from the system operator and that are required to be provided by the system operator to the Authority under this Code.
(2) The Authority must publish each report within 5 working days after receiving the report.

Part 8

8.10C Authority may require system operator to reconsider

(1) The Authority may require the system operator to reconsider a decision made under clause 8.10A(1)(b) not to propose a change to the policy statement.
(2) If the Authority requires the system operator to reconsider a decision made under subclause 8.10A(1)(b), the Authority must advise the system operator of—
   (a) the Authority’s reasons for requiring the system operator to reconsider; and
   (b) the date, determined after consulting with the system operator, by which the system operator must either confirm its decision or submit a draft policy statement.
(3) The Authority must as soon as practicable publish the advice received from the system operator under clause 8.10A(1)(c) and the advice given by the Authority to the system operator under subclause (2).

8.11A Changes and variations

(1) The system operator may at any time propose a change to the policy statement by submitting a draft policy statement to the Authority together with the following information:
   (a) an explanation of the proposed change and a statement of the objectives of the proposed change:
   (b) an evaluation of alternative means of achieving the proposed change:
   (c) an evaluation of the costs and benefits of the proposed change.
(2) The Authority or a participant may at any time request that the system operator propose a change to the policy statement under subclause (1).

(3) If the system operator receives a request under subclause (2), it must as soon as practicable—
   (a) decide whether to decline the request, defer the request until the next review date, or submit a draft policy statement to the Authority; and
   (b) publish the decision on its website.

8.12 Consultation on draft policy statement
(1) The Authority must publish the following information as soon as practicable after it receives it:
   (a) a draft policy statement submitted under clause 8.10A and the information required under clause 8.10A(2);
   (b) a draft policy statement submitted under clause 8.11A and the information required under clauses 8.11A(1)(a) to (c).

(2) When the Authority publishes a draft policy statement and information under subclause (1), the Authority must advise participants of the date (which must not be earlier than 10 business days after the date that the Authority publishes the draft policy statement) by which submissions on the changes proposed in the draft policy statement must be received by the Authority.

(3) Each submission on changes proposed in a draft policy statement must be made in writing to the Authority and received on or before the submission expiry date.

(4) The Authority must provide a copy of each submission received to the system operator at the close of business on the submission expiry date and must publish the submissions as soon as practicable.

(5) The system operator may make its own submission on the draft policy statement and the submissions received in relation to it no later than 10 business days after the submission expiry date.

(6) The Authority must publish the system operator’s submission as soon as practicable after it is received.

(7) Following the consultation process required by subclauses (1) to (6), the Authority may approve the draft policy statement subject to the system operator making any changes that the Authority considers appropriate.

8.12A Technical and non-controversial changes

(4) If the Authority approves the draft policy statement it must as soon as practicable—
   (a) publish notice of its intention to incorporate the draft policy statement by reference into this Code; and
   (b) include in the notice the Authority’s reasons for considering that the changes proposed in the draft policy statement are technical and non-controversial; and
   (c) invite comment from participants on the reasons given in the notice.

(5) After considering any comments made under subclause 4(c) the Authority must advise the system operator by notice in writing of its decision as to whether to confirm or revoke its approval of the draft policy statement, and give reasons for its decision.

(6) The Authority must publish its decision and reasons as soon as practicable.
8.12B Authority adopts new policy statement

If the Authority approves a draft policy statement under clause 8.12 or confirms its approval of a draft policy statement under clause 8.12A it must—
(a) incorporate the new policy statement by reference into this Code in accordance with Schedule 1 of the Act; and
(b) publish the new policy statement and the date on which it takes legal effect.

8.14 Departure from policy statement

(1) The system operator may depart from the policies set out in a policy statement when a system security situation arises and such departure is required for the system operator to comply with clause 7.1A(1).

(2) If the system operator departs from a policy statement under subclause (1), the system operator must provide a report to the Authority setting out the circumstances of the system security situation and the actions taken to deal with it.

(3) The Authority must publish the report within a reasonable time after receiving it.

8.42C Authority may require system operator to reconsider

(1) The Authority may require the system operator to reconsider a decision made under clause 8.42A(1)(b) not to propose a change to the procurement plan.

(2) If the Authority requires the system operator to reconsider a decision made under subclause 8.42A(1)(b) the Authority must advise the system operator of—
(a) the Authority’s reasons for requiring the system operator to reconsider; and
(b) the date, determined after consulting the system operator, by which the system operator must either confirm its decision or submit a draft procurement plan.

(3) The Authority must as soon as practicable publish the advice received from the system operator under clause 8.42A(1)(c) and the advice given by the Authority to the system operator under subclause (2).

8.43A Changes and variations

(1) The system operator may at any time propose a change to the procurement plan by submitting a draft procurement plan to the Authority together with the following information:
(a) an explanation of the proposed change and a statement of the objectives of the proposed change;
(b) an evaluation of alternative means of achieving the objectives of the proposed change;
(c) an evaluation of the costs and benefits of the proposed change.

(2) The Authority or a participant may at any time request that the system operator propose a change to the procurement plan under subclause (1).

(3) If the system operator receives a request under subclause (2), it must as soon as practicable—
(a) decide whether to decline the request, defer the request until the next review date, or submit a draft procurement plan to the Authority; and
(b) publish the decision on its website.

8.44 Consultation on draft procurement plan
(1) The Authority must publish the following information as soon as practicable after it receives it:
   (a) a draft procurement plan submitted under clause 8.42A and the information required under clause 8.42A(2);
   (b) a draft procurement plan submitted under clause 8.43A and the information required under clause 8.43A(1)(a) to (c).
(2) When the Authority publishes a draft procurement plan and information under subclause (1) the Authority must advise participants of the date (which must not be earlier than 10 business days after the date that the Authority publishes the draft procurement plan) by which submissions on the changes proposed in the draft procurement plan must be received by the Authority.
(3) Each submission on changes proposed in a draft procurement plan must be made in writing to the Authority and received on or before the submission expiry date.
(4) The Authority must provide a copy of each submission received to the system operator at the close of business on the submission expiry date and must publish the submissions as soon as practicable.
(5) The system operator may make its own submission on the draft procurement plan and the submissions received in relation to it no later than 10 business days after the submission expiry date.
(6) The Authority must publish the system operator’s submission as soon as practicable after it is received.
(7) Following the consultation process required by subclauses (1) to (6), the Authority may approve the draft procurement plan subject to the system operator making any changes that the Authority considers appropriate.

8.44A Technical and non-controversial amendments
   ...
(4) If the Authority approves the draft procurement plan it must as soon as practicable—
   (a) publish notice of its intention to incorporate the draft procurement plan by reference into this Code; and
   (b) include in the notice the Authority’s reasons for considering that the changes proposed in the draft procurement plan are technical and non-controversial; and
   (c) invite comment from participants on the reasons given in the notice.
(5) After considering any comments made under subclause 4(c) the Authority must advise the system operator by notice in writing of its decision as to whether to confirm or revoke its approval of the draft procurement plan, and give reasons for its decision.
(6) The Authority must publish its decision and reasons as soon as practicable.

8.44B Authority adopts new procurement plan
If the Authority approves a draft procurement plan under clause 8.44 or confirms its approval of a draft procurement plan under clause 8.44A it must—
(a) incorporate the new procurement plan by reference into this Code in accordance with Schedule 1 of the Act; and
(b) **publishpublicise** the new **procurement plan** and the date on which it takes legal effect.

8.45A Methodology to assess net purchase quantity

The **system operator** must make the **net purchase quantity assessment** for each relevant **ancillary service** using the methodology in the **procurement plan** and **publish** the results of the assessment on its website as soon as practicable.

8.47 Departure from procurement plan

(1) The **system operator** may depart from the processes and arrangements set out in the **procurement plan** if the **system operator** reasonably considers it necessary to do so to comply with the **principal performance obligations**.

(2) When the **system operator** makes a departure under subclause (1), the **system operator** must provide a report to the **Authority** setting out the circumstances of the departure and the actions taken to deal with it.

(3) The **Authority** must **publishpublicise** the report within a reasonable time after receiving it.

8.54F Authority may require system operator to reconsider

(1) The **Authority** may require the **system operator** to reconsider a decision made under clause 8.54E(1)(c) not to propose a change to the **extended reserve technical requirements schedule**.

(2) If the **Authority** requires the **system operator** to reconsider, the **Authority** must advise the **system operator** of—

(a) the **Authority**'s reasons for requiring the **system operator** to reconsider; and

(b) the date, determined after consulting with the **system operator**, by which the **system operator** must—

(i) confirm its decision under clause 8.54E(1)(c); or

(ii) provide a draft of the revised schedule to the **Authority** under clause 2(2) of Schedule 8.5.

(3) The **Authority** must as soon as practicable **publishpublicise** the advice received from the **system operator** under clause 8.54E(1)(c) and any advice given by the **Authority** to the **system operator** under subclause (2).

8.54Q System operator to give written notice advise clearing manager of dates

(1) The **system operator** must **give written notice** to advise the **Authority** and the **clearing manager** of all dates on which **extended reserve providers** will provide, or cease to provide, **extended reserve**, as set out in the **extended reserve schedule**.

(2) If an amendment to an implementation plan made under clause 8.54M(6) or (7) results in an **extended reserve provider** providing, or ceasing to provide, any **extended reserve** on a date that is different from the relevant date specified in the implementation plan, in each case the **system operator** must—

(a) update the **extended reserve schedule** with the new date; and

(b) **give written notice** to advise the **Authority** and the **clearing manager** of the new date.
8.54T Assignment of extended reserve obligations

(1) An extended reserve provider that proposes to assign assets that it uses to provide extended reserve may apply to the Authority by notice in writing for approval to assign its obligations to provide extended reserve that relate to those assets.

(2) The Authority may, on receiving an application under subclause (1),—
(a) approve the assignment; or
(b) approve the assignment with conditions; or
(c) decline to approve the assignment.

(3) Before giving an extended reserve provider approval to assign its obligations under subclause (2), the Authority must consult with the system operator.

(4) If the Authority gives an extended reserve provider approval to assign its obligations under subclause (2), the Authority must give written notice to advise the system operator.

(5) An assignment of an extended reserve provider's obligations is not effective except as approved by the Authority under subclause (2).

Schedule 8.3, Technical Code B
7 Extended reserve providers to provide extended reserve

(1) Each extended reserve provider must provide extended reserve at all times in accordance with its current statement of extended reserve obligations issued by the system operator under clause 8.54P.

(2) An extended reserve provider must give written notice to advise the system operator as soon as practicable if the extended reserve provider is unable to comply with subclause (1).

Schedule 8.3, Technical Code C
5 Specific requirements for document transmission communication

(1) Subject to subclause (2) and the information system, Each asset owner's control room must give information to use facsimile transmission as the primary means of transmitting a document between the control room of the asset owner and the system operator in writing.

(2) An asset owner may request the system operator to approve an alternative primary means of transmitting information a document (such approval not to be unreasonably withheld).

(3) Each asset owner must have in place a backup means of transmitting information a document. The backup means of transmitting information document transmission communication—
(a) must be approved by the system operator (such approval not to be unreasonably withheld); and
(b) may include, but is not limited to, voice communication or email; and
(c) may only be used if the primary means of document transmission described in subclause (1) or (2) is unavailable or otherwise with the agreement of the system operator.

Schedule 8.5
3 Technical and non-controversial changes

(1) The system operator may at any time make a change to the extended reserve technical
requirements schedule that it considers is technical and non-controversial.

(2) If the system operator makes a change to the extended reserve technical requirements schedule under subclause (1), the system operator is not required to comply with clause 2 of this Schedule.

(3) The system operator must give written notice to advise the Authority of any changes to the extended reserve technical requirements schedule made under this clause.

6 Approval of extended reserve selection methodology

... (4) If the Authority declines to approve the draft methodology, the Authority must either—
(a) publish the changes that the Authority wishes the extended reserve manager to make to the draft methodology; or
(b) require the extended reserve manager to prepare a new draft methodology.

7 Consultation on proposed changes

(1) When the Authority publishes changes that the Authority wishes the extended reserve manager to make to the draft extended reserve selection methodology under clause 6(4), the Authority must advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(2) Each submission on the changes to the draft methodology must be made in writing to the Authority and be received by the date specified by the Authority.

(3) The Authority must—
(a) give a copy of each submission made to the extended reserve manager; and
(b) publish the submissions.

(4) The extended reserve manager may make its own submission on the changes to the draft methodology and the submissions made in relation to the changes.

(5) The Authority must publish the extended reserve manager's submission when it is received.

(6) The Authority must consider the submissions made to it on the changes to the draft methodology and prepare a revised draft methodology incorporating any amendments that the Authority proposes be made to the methodology.

(7) The Authority must give the revised draft methodology prepared under subclause (6) to the system operator, and clause 6(2) applies as if the revised draft methodology was the draft methodology prepared under clause 5.

(8) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must,—
(a) by notice in writing to the extended reserve manager and the system operator,—
(i) approve the revised draft methodology; or
(ii) amend the revised draft methodology to address any comments received from the system operator, and approve it; or
(b) publish a further revised draft methodology, and advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(9) If the Authority publishes a further revised draft methodology under subclause (8)(b), subclauses (2) to (8) apply as if the further revised draft methodology was the revised draft methodology.
8 Technical and non-controversial changes

(1) The extended reserve manager may at any time propose a change to the extended reserve selection methodology that it considers is technical and non-controversial by giving a draft methodology to the Authority together with an explanation of the proposed change.

(2) If the extended reserve manager gives a draft methodology to the Authority under subclause (1) the extended reserve manager is not required to comply with clauses 5 and 6 of this Schedule.

(3) The Authority must give written notice to advise the system operator of any proposed change to the extended reserve selection methodology that it receives under subclause (1).

(4) The Authority must, as soon as practicable after receiving a draft methodology and the information required by subclause (1), by notice in writing to the extended reserve manager and the system operator—
   (a) approve the draft methodology; or
   (b) decline to approve the draft methodology, giving reasons.

12 Approval of extended reserve procurement schedule

(1) The extended reserve manager must give the Authority and the system operator—
   (a) a copy of each submission made on the draft extended reserve procurement schedule; and
   (b) a response to each issue raised by each submission; and
   (c) a copy of the draft procurement schedule that the extended reserve manager proposes to publish.

(2) As soon as practicable, but no later than 15 business days after receiving a copy of the draft procurement schedule, the system operator must—
   (a) give the Authority any comments it wishes to make on the draft procurement schedule; or
   (b) advise the Authority that it does not wish to make any comments.

(3) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must, by notice in writing to the extended reserve manager and the system operator,—
   (a) approve the draft procurement schedule; or
   (b) decline to approve the draft procurement schedule.

(4) If the Authority declines to approve the draft procurement schedule, the Authority must either—
   (a) publish the changes that the Authority wishes the extended reserve manager to make to the draft procurement schedule; or
   (b) require the extended reserve manager to prepare a new draft procurement schedule.

13 Consultation on proposed changes

(1) When the Authority publishes changes that the Authority wishes the extended reserve manager to make to the draft extended reserve procurement schedule under clause 12(4), the Authority must advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.
Each submission on the changes to the draft procurement schedule must be made in writing to the Authority and be made by the date advised by the Authority.

3. The Authority must—
   (a) give a copy of each submission made to the extended reserve manager; and
   (b) the submissions.

4. The extended reserve manager may make its own submission on the changes to the draft procurement schedule and the submissions made in relation to the changes.

5. The Authority must publish the extended reserve manager’s submission when it is received.

6. The Authority must consider the submissions made to it on the changes to the draft procurement schedule and prepare a revised draft procurement schedule incorporating any amendments that the Authority proposes be made to the schedule.

7. The Authority must give the revised draft procurement schedule prepared under subclause (6) to the system operator, and clause 12(2) applies as if the revised draft procurement schedule was the draft procurement schedule prepared under clause 11.

8. As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must,—
   (a) by notice in writing to the extended reserve manager and the system operator,—
      (i) approve the revised draft procurement schedule; or
      (ii) amend the revised draft procurement schedule to address any comments received from the system operator, and approve it; or
   (b) publish a further revised draft procurement schedule, and advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

9. If the Authority publishes a further revised draft procurement schedule under subclause (8)(b), subclauses (2) to (8) apply as if the further revised draft procurement schedule was the revised procurement schedule.

Part 9

9.5 Amendments and substitutions of system operator rolling outage plans

1. The system operator may—
   (a) amend a system operator rolling outage plan; or
   (b) revoke a system operator rolling outage plan and substitute a new plan.

2. This subpart applies to an amendment to a plan or a substitute plan—
   (a) as if the amendment or substitute plan were the original plan; and
   (b) with other necessary modifications.

3. The system operator must not submit an amended or new system operator rolling outage plan to the Authority under clause 9.2(2) unless the system operator has—
   (a) consulted with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by the amended or new plan; and
   (b) considered submissions made on the amended or new plan.

4. Subclause (3) does not apply if the system operator considers that it is necessary or desirable in the public interest that the proposed system operator rolling outage plan be published urgently, and, in this case, the system operator rolling outage plan, and the
notice in the Gazette that is part of the publishing of the plan, must state that the plan is published in reliance on this subclause and then, within 6 months of the plan being published, the system operator must—
(a) comply with subclause (3); and
(b) decide whether or not the plan should be amended or revoked and a new plan substituted; and
(c) no later than 10 working days after making that decision, publish the decision; and
(d) if the system operator decides that the plan should be amended or revoked and a new plan substituted, comply with this clause in relation to the proposed amendment or revocation and substitution.

(5) To avoid doubt, a system operator rolling outage plan is not invalid only because the system operator did all or any of the things referred to in subclause (3) before this clause came into force.

9.13B Request for urgent temporary grid reconfiguration

…

(3) No later than 10 business days after giving notice to Transpower, the system operator must give a written report to the Authority setting out the basis on which the system operator requested that Transpower remove 1 or more interconnection assets from service or temporarily reconfigure the grid.

(4) The system operator must ensure that the report given under subclause (3) includes—
(a) the matters specified in subclause (2)(a) and (b); and
(b) sufficient information to demonstrate that in developing its request to Transpower the system operator followed a robust process, including the options the system operator considered and the extent of any analysis and consultation undertaken by the system operator.

(5) The Authority must publish the report.

9.15 Power to direct outages in security of supply situation

(1) The system operator may, at any time in the period during which a supply shortage declaration is in force, give a written direction to specified participants to contribute to achieving reductions in the consumption of electricity by implementing outages or taking any other action specified in the direction.

(2) A direction must—
(a) be consistent with the system operator rolling outage plan; and
(b) be given only after consultation with the Authority; and
(c) if the direction requires a specified participant to implement outages, specify the savings targets that the specified participant must achieve.

(3) A direction may be communicated through the information system operated by the system operator.

(4) The system operator must publish each direction as soon as practicable after it is given.

(5) The system operator may—
(a) amend a direction; or
(b) revoke a direction and, if the system operator considers it appropriate, substitute a new direction.

(6) Subclauses (1) to (4) apply to an amendment to a direction or a substitute direction—
(a) as if the amendment or substitute direction were the original direction; and
(b) with other necessary modifications.

9.23 System operator commences official conservation campaign

... (5) If the system operator and the Authority agree under subclause (1)(b) or (2)(b) that an official conservation campaign will commence, the system operator must make publicly available on its website the reasons for agreeing that the official conservation campaign will commence.

9.25 Authority must determine minimum weekly amount

(1) In determining the minimum weekly amount that each retailer must pay to its qualifying customers, the Authority must take into account—
   (a) the estimated value, in dollars/MWh, of the savings that the Authority expects all qualifying customers in the South Island or New Zealand, as the case may be, of all retailers, will achieve during an official conservation campaign; and
   (b) any other factors that the Authority considers relevant.

(2) The Authority must—
   (a) publish the minimum weekly amount; and
   (b) review the minimum weekly amount—
      (i) after each public conservation period ends; and
      (ii) at least once every 3 calendar years; and
   (c) following a review under paragraph (b), ensure that it gives participants at least 3 months’ notice if it determines a new minimum weekly amount.

9.28 Publishing description of additional customer compensation schemes

A retailer who has 1 or more additional customer compensation schemes must—
(a) publish and keep published a description of its additional customer compensation schemes publicly available, at no cost, on an Internet site maintained by or on behalf of the retailer, at all reasonable times; and
(b) on request from a customer, provide a written description of the additional customer compensation schemes.

Part 10

10.49 NSP table

(1) The market administrator must publish and maintain an NSP table, or ensure that an NSP table is published and maintained, on the Authority’s website.

(2) The reconciliation manager must advise the market administrator of any change to the information contained in the NSP table within 1 business day of becoming aware of such change.

(3) The market administrator must update the NSP table, or ensure that the NSP table is updated, within 2 business days of being advised by the reconciliation manager under subclause (2).
Part 11

11.15AA Trader may elect to have switch saving protection

(1) A trader that buys electricity from the clearing manager may elect to have switch saving protection by giving written notice to the Authority.

(2) The Authority must publish the name of each trader that has elected to have switch saving protection as soon as practicable after receiving the written notice from the trader.

(3) A trader’s switch saving protection comes into effect on the day after the day on which the Authority publishes the trader’s election.

11.32B Requests for information

(1) A retailer to which a request is made must give the information to the consumer no later than 5 business days after the date on which the request is made.

(2) In responding to a request, the retailer must comply with the procedures, and any relevant EIEP, published by the Authority under clause 11.32F.

(3) A retailer must not charge a fee for responding to a request, but if 4 requests in respect of a consumer's information have been made in a 12 month period, the retailer may impose a reasonable charge for further requests in that 12 month period.

11.32F Authority to publish procedures for responding to requests for consumption information

(1) The Authority must, no later than 20 business days after this clause comes into force, publish—

(a) procedures under which a retailer must respond to a request from a consumer under clause 11.32B; and

(b) 1 or more EIEPs with which a retailer must comply when responding to such a request.

(2) The procedures published by the Authority must specify the manner in which information must be given to consumers.

(3) Each EIEP published by the Authority must specify 1 or more formats in which information must be given to consumers.

(4) Before the Authority publishes an EIEP under subclause (1), or amends an EIEP that it has published under subclause (1), it must consult with the participants that the Authority considers are likely to be affected by the EIEP.

(5) The Authority need not comply with subclause (4) if it proposes to amend an EIEP under subclause (1) if the Authority is satisfied that—

(a) the nature of the amendment is technical and non-controversial; or

(b) there has been adequate prior consultation so that the Authority has considered all relevant views.

Schedule 11.1

9 Traders to provide ICP information to registry

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

(a) the participant identifier of the trader:
(b) the **profile** code of each **profile** at that ICP approved by the **market administrator** in accordance with clause 13 of Schedule 15.5:

(c) the **participant identifier** of the **metering equipment provider** for each **category 1 metering installation**, or higher category **metering installation**, for the ICP:

(d) [Revoked]

(e) [Revoked]

(ea) the type of **submission information** that the **trader** will provide to the **reconciliation manager** for the ICP:

(f) if the settlement type UNM is assigned to the ICP—
   (i) if the load is profiled through an engineering **profile** in accordance with **profile class** 2.1, the code ENG; or
   (ii) in all other cases, the daily average **unmetered load** in kWh at the ICP:

(g) the type and capacity of the **unmetered load** at the ICP (if any):

(h) [Revoked]

(i) [Revoked]

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

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

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### Part 12

#### 12.10 Benchmark agreements to be default transmission agreements

(1) Subject to clauses 12.49 and 12.50, if, at the expiry of 2 months after a **participant** becomes a **designated transmission customer**, the **designated transmission customer** and Transpower have not entered into a **transmission agreement** in accordance with clause 12.9, the **benchmark agreement** applies as a binding contract between the **designated transmission customer** and Transpower, and the **designated transmission customer** and Transpower must comply with the process specified in this clause.

(2) If this clause applies:

(a) within 10 **business days** of the date that is 2 months after the **participant** became a **designated transmission customer**, 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, facsimile number 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) by the date 20 **business days** after the 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 **benchmark agreement**, which must include the following:
   (i) the **designated transmission customer’s** details as provided under paragraph (a):
(ii) Transpower’s physical address, postal address and electronic address facsimile number to which notices under the default transmission agreement are to be sent:

(iii) the contact person to whom notices under the default transmission agreement should be addressed:

(iv) Transpower’s designated bank account for the purposes of receiving payments under the default transmission agreement:

(v) a draft Schedule 1, which sets 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:

(vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the benchmark agreement, the configuration of the connection assets in relation to each connection location listed in Schedule 1:

(vii) a draft Schedule 5 setting out proposed service levels for each connection location listed in Schedule 1 determined in accordance with subclause (3):

(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 the schedule and the licence charges under the schedule:

12.13 Expiry or termination of transmission agreements

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 facsimile number 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 benchmark agreement, 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 facsimile number 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) a draft Schedule 1, which sets 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 benchmark agreement, 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

12.112 Exceptions to clause 12.111

... (3) If a decision to remove an asset, or reconfigure the grid, or reduce the transmission capacity of an asset has been made under subclause (1)(b)(i) or (ii), Transpower must as soon as reasonably possible publish make publicly available the analysis it undertook in accordance with subclause (1)(b)(i) or (ii), or a summary of that analysis.

12.116AC Information to be publishedpublicly available

If Transpower receives a notice given in accordance with clause 9.13B, Transpower must make publish publicly available at no cost, on an Internet site maintained by or on behalf of Transpower,—

(a) as soon as practical, a copy of the notice; and

(b) by no later than 5 business days after receiving the notice, a summary of Transpower’s application of the net benefit test that relates to the exceptional circumstances stated in the notice.

Schedule 12.4

3 Definitions and interpretation

... transition date means the date of the last ODV report published by Transpower's website before the date on which this transmission pricing methodology takes effect...

42 Prudent Discount Details to be Published
(1) As soon as reasonably practicable after concluding a prudent discount agreement with a customer, Transpower must publish on its website the decision made, the analysis supporting that decision and the following information:
   (a) the cost estimate used by Transpower in assessing the alternative project and the calculations undertaken by Transpower using those cost estimates:
   (b) any report prepared by an independent expert:
   (c) the annual amount payable by the customer under clause 41(1)(a):
   (d) details of how the customer’s transmission charges will be calculated under clause 41(1)(b).

Part 12A

12A.1 Contents of this Part
   This Part—
   ...
   (g) provides that the Authority may publish EIEPs that distributors and traders must comply with when exchanging information.

12A.13 Authority may publish EIEPs that must be used
   (1) The Authority may publish 1 or more EIEPs that set out standard formats that distributors and traders must use when exchanging information.
   (2) When publishing an EIEP under subclause (1), the Authority must specify the date on which the EIEP will come into effect.
   (3) The information to which an EIEP published under subclause (1) may relate includes, but is not limited to, the following information:
      (a) ICP level billing information:
      (b) level billing information:
      (c) half hourly billing information:
      (d) distributor tariff rate change information.
   (4) Before the Authority publishes an EIEP under clause 12A.13, or amends an EIEP it has published under subclause (1), it must consult with the participants that the Authority considers are likely to be affected by the EIEP.
   (5) The Authority need not comply with subclause (4) if it proposes to amend an EIEP under subclause (1) if the Authority is satisfied that—
      (a) the nature of the amendment is technical and non-controversial; or
      (b) there has been adequate prior consultation so that the Authority has considered all relevant views.
   (6) [Revoked]

12A.14 Distributors and traders must comply with EIEPs
   (1) If the Authority published an EIEP under clause 12A.13, the distributor and the trader must, when exchanging information to which the EIEP relates, comply with the EIEP from the date on which the EIEP comes into effect.
   (2) [Revoked]
However, a distributor and a trader may, after an EIEP has been published, agree to exchange information other than in accordance with the EIEP, by recording the agreement in each use-of-system agreement between the distributor and trader.

An agreement to exchange information other than in accordance with an EIEP is not effective in relieving a distributor and a trader of the obligation to comply with subclause (1), unless the agreement comes into effect on or after the date on which the relevant EIEP comes into effect.

An agreement under subclause (3) is not affected by the Authority publishing an amendment to the EIEP.

Subclause (1) does not apply to an EIEP published under clause 12A.15.

Authority may publish voluntary EIEPs

The Authority may publish 1 or more EIEPs that set out standard formats that distributors and traders may, but are not required to, use when exchanging information.

Transitional provision relating to EIEPs

This clause applies to any EIEP that a distributor or trader was required to comply with immediately before this clause came into force.

An EIEP to which this clause applies—
(a) is deemed to be an EIEP published under clause 12A.13(1); and
(b) despite clause 12A.13(2), comes into effect on the date on which this clause comes into force.

The Authority need not comply with clause 12A.13(4) in respect of an EIEP to which this clause applies, unless the Authority proposes to amend the EIEP.

[Revoked]

Part 13

System operator to prepare forecast of non-dispatch-capable load at conforming GXPs

The system operator must prepare a forecast of non-dispatch-capable load for each conforming GXP for each trading period in a schedule period.

The system operator must—
(a) disclose to the Authority a description of the processes and methodology it uses to prepare the forecast under subclause (1); and
(b) publish and keep published make available to the public on the system operator’s website at all reasonable times, either—
(i) the description it disclosed to the Authority under paragraph (a); or
(ii) a summary of the processes and methodology it uses to prepare the forecast under subclause (1).

Despite subclause (2), the system operator is required to disclose or publish to make information available under subclause (2) only if the information—
(a) is available to the system operator; and
(b) is not confidential or commercially sensitive.
13.22 Transmission of information through information system
(1) Except where specified otherwise in clauses 13.6 to 13.27, all information required to be submitted by a purchaser or generator under clauses 13.6 to 13.27 must be transmitted to the system operator through WITS, the electronic facility contained in the information system.

(2) The system operator must immediately confirm receipt of any information that the system operator receives from a purchaser or generator under clauses 13.6 to 13.27 through the electronic facility contained in the information system. Each confirmation must contain a copy of the information received by the system operator together with the time of receipt.

(3) If a purchaser or generator has not received the confirmation within 10 minutes after the information has been sent, the purchaser or generator submitted the information under clauses 13.6 to 13.27 to the system operator, the purchaser or generator must telephone the system operator to check whether the system operator has received the information. If the system operator has not received the information, the purchaser or generator must resend the information. The process set out in this clause must then be repeated until the system operator has confirmed receipt of the information from the purchaser or generator.

13.23 Backup procedures if WITS information system is unavailable
(1) If WITS, the information system 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 by the WITS manager—

market administrator.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager following consultation with each purchaser, generator and the system operator. The market administrator must ensure that there is always a backup procedure notified to each purchaser, generator and the system operator.

13.27C Process for making a determination
...

(2) The Authority must make a determination in accordance with the methodology in Schedule 13.7, unless—
(a) the Authority has applied the methodology; and
(b) according to the methodology, the GXP is a conforming GXP; and
(c) the Authority considers that the GXP should be treated as a non-conforming GXP; and
(d) the Authority has published criteria under clause 13.27E; and
(e) making a determination that the GXP is a non-conforming GXP is in accordance with the criteria.

(3) If paragraphs (a) to (e) in subclause (2) apply, the Authority may make a determination in accordance with the criteria published under clause 13.27E.

(4) As soon as practicable after making a determination, the Authority must—
(a) advise the wholesale information trading system provider, all purchasers, and the system operator—
(i) of its determination; and
(ii) whether, in making the determination, the Authority has followed—
(A) the methodology set out in Schedule 13.7; or
(B) the criteria published under clause 13.27E; and
(b) advise all purchasers and the system operator of the right to request, under clause 13.27H, a reconsideration of the determination; and
(c) if the determination was requested under clause 13.27H, provide reasons for its decision to the requester.

13.27E Authority may publish criteria for determining GXP to be non-conforming
(1) The Authority may publish criteria that set out the circumstances in which the Authority may make a determination that does not follow the methodology set out in Schedule 13.7.
(2) The Authority must consult with participants before—
(a) publishing the criteria under subclause (1):
(b) amending the criteria published under subclause (1).

13.27G Authority must publish and maintain list of non-conforming and conforming GXPs
The Authority must publish and maintain a list of all non-conforming GXPs and all conforming GXPs, including—
(a) the mean demand (in MW) for each GXP calculated in accordance with clause 1(b) of Schedule 13.7; and
(b) if the mean demand for a GXP is 10 MW or more, the unpredictability measure for the GXP calculated in accordance with clause 1(c) of Schedule 13.7.

13.35 System operator to confirm receipt of Transmission of grid owner information through information system
(1) All information required to be submitted by a grid owner under clauses 13.29 to 13.36 must be transmitted to the system operator through the electronic facility contained in the information system.
(2) The system operator must immediately confirm in writing to each grid owner receipt of all information received from that grid owner under clauses 13.29 to 13.36 through the electronic facility contained in the information system. The confirmation must also contain a record of the time of receipt.

13.36 Backup procedures if information system is unavailable
(1) If the information system is unavailable to receive information or confirm the receipt of information, the grid owner or the system operator, as the case may be, must follow the backup procedures specified by the market administrator.
(2) The backup procedures referred to in subclause (1) must be specified by the market administrator following consultation with grid owners and the system operator. The market administrator must ensure that there is always a backup procedure notified to grid owners and the system operator.
13.51 Transmission of reserve offers through WITS information system

(1) All reserve offers or cancellations of reserve offers submitted by an ancillary service agent under clauses 13.37 to 13.54 must be transmitted to the system operator through WITS, the electronic facility contained in the information system.

(2) The system operator must immediately confirm receipt to the ancillary service agent of all reserve offers or cancellations of reserve offers received from the ancillary service agent through WITS, the electronic facility contained in the information system. Such confirmation must also contain a copy of the reserve offer or cancellation of reserve offer received by the system operator, together with the time of receipt.

(3) If an ancillary service agent has not received confirmation that the system operator has received its reserve offer or cancellation of a reserve offer has been received by the system operator within 10 minutes after the ancillary service agent submitted the reserve offer or cancellation of a reserve offer has been sent, the ancillary service agent must telephone the system operator to check whether the system operator has received the reserve offer or cancellation of a reserve offer has been. If it has not, the ancillary service agent must resend the reserve offer or cancellation of a reserve offer. The processes set out in this clause must then be repeated until the system operator confirms receipt of the reserve offer or cancellation of a reserve offer from the ancillary service agent.

13.52 Backup procedures if WITS information system is unavailable

(1) If the WITS information system is unavailable to receive reserve offers or cancellations of reserve offers or to confirm the receipt of such reserve offers or cancellations, an ancillary service agent or the system operator, as the case may be, must follow the backup procedures specified by the WITS manager/market administrator.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager/market administrator following consultation with ancillary service agents and the system operator. The market administrator must ensure that there is always a backup procedure notified to the ancillary service agents and the system operator.

13.55 Availability of bids, offers, and reserve offers

(1) The market administrator must, within 24 hours of the end of each day, publish and make available on WITS all final bids, final offers and final reserve offers received for the trading periods of the previous trading day.

(2) All information published and to be made available on WITS by the market administrator under this clause must be—

(a) transmitted to participants through the electronic facilities contained in the information system; and

(b) placed on a publicly accessible website— and must remain available for inspection through WITS, the electronic facilities contained in the information system and kept published on the publicly accessible website, for a period of at least 4 weeks.

(3) If the WITS information system is unavailable to send information under subclause (2)(a), the market administrator must follow the backup procedures specified by the WITS manager/market administrator from time to time.
(4) The backup procedures referred to in subclause (3) must be put in place by the WITS market administrator in consultation with purchasers, generators and ancillary service agents. The market administrator must ensure that there is always a backup procedure notified to the purchasers, generators and ancillary service agents.

(5) If the publicly accessible website on which information is to be published placed under subclause (2)(b) is not available, the WITS market administrator is not obliged to follow any backup procedures, but the WITS market administrator must publish the information available as soon as practicable once the publicly accessible website becomes available.

(6) [Revoked]

(7) [Revoked]

13.58 Process for preparing price-responsive schedule and non-response schedule

(1) The system operator must prepare—
   (a) a price-responsive schedule; and
   (b) a non-response schedule.

(1A) The system operator must prepare the schedules listed in subclause (1) in accordance with the timing required under clause 13.62.

(2) [Revoked]

(3) [Revoked]

(3A) In preparing each price-responsive schedule, the system operator must—
   (a) use the most recent information received under subpart 1; and
   (b) use all other information described in clause 13.58A(1); and
   (c) act in accordance with Schedule 13.3.

(3B) In preparing each non-response schedule, the system operator must—
   (a) use the most recent information received under subpart 1; and
   (b) use all other information described in clause 13.58A(2); and
   (c) act in accordance with Schedule 13.3.

(4) As soon as practicable after the system operator has completed preparing a price-responsive schedule and a non-response schedule, the system operator must make available send the price-responsive schedule and the non-response schedule to the clearing manager through WITS.

13.63 Trading period information to be given to pricing manager and clearing manager

The system operator must, by 0730 hours of each trading day, make available send to the pricing manager and clearing manager the final information provided to the system operator under subpart 1 in relation to each trading period of the previous trading day through WITS or through an approved system.

13.67 Transmission of information through information system

(1) All information to be made available by the system operator to the clearing manager or the pricing manager under clauses 13.58 to 13.66 must be transmitted through the electronic facility contained in the information system.

(2) If WITS or the approved system is unavailable to make send information available under clauses 13.58 to 13.66, the system operator must follow the backup procedures specified by the WITS market administrator.
(3) The backup procedures referred to in subclause (2) must be specified by the WITS manager, market administrator following consultation with the system operator, the clearing manager, and the pricing manager. The market administrator must ensure that there is always a backup procedure notified to the system operator, the clearing manager, and the pricing manager.

13.76 Dispatch instructions to be issued and logged
(1) The system operator must issue dispatch instructions,—
(a) to each generator, using an approved system;
(b) to each dispatchable load purchaser that has submitted a nominated dispatch bid; through WITS; and
(c) to each ancillary service agent, verbally or in writing, the electronic facilities specified in the information system to—
(a) each generator; and
(b) each dispatchable load purchaser that has submitted a nominated dispatch bid.
(2) The system operator must use either voice communication or electronic communication (if such facility exists) to issue dispatch instructions to each ancillary service agent.
(3) The system operator must log and record each dispatch instruction.
(4) Each generator and each ancillary service agent must log each dispatch instruction received from the system operator.
(5) The system operator must provide a copy of each dispatch instruction—
(a) to the clearing manager, by 1600 hours on the 7th business day of the billing period after the billing period in which the system operator issues and logs the dispatch instruction; and
(b) to the Authority, by 1600 hours on the first business day after the day on which the system operator issues and logs the dispatch instruction.
(6) For the purpose of subclause (5), if the system operator has issued more than 1 dispatch instruction for a dispatch-capable load station for the same trading period, the system operator must provide a copy of the latest dispatch instruction.

13.90 Process for publishing real time prices
(1) The system operator must use reasonable endeavours to make available on WITS publish, for each real time pricing period, as soon as practicable after the real time pricing period,—
(a) a schedule of real time prices; and
(b) the following additional information for each schedule of real time prices:
   (i) the number of transmission lines or transformers that have a MW arc flow equal to the maximum flow limit (in MW) on that transmission line or transformer set by the grid owner in accordance with clauses 13.29 to 13.32:
   (ii) the number of groups of transmission lines or transformers, or both, that have a total MW arc flow equal to the relevant maximum flow limit (in MW) as set by the system operator in accordance with Schedule 13.3:
   (iii) the aggregate of the following occurrences:
      (A) the number of occurrences at which energy (in MW) for a generator at a set of grid injection points is equal to the minimum and/or maximum generation (in MW) for that set of grid injection points set by the system operator in accordance with Schedule 13.3:
(B) the number of occurrences at which energy (in MW) and reserves (in MW) for a generator at a set of grid injection points is equal to the maximum generation (in MW) for that set of grid injection points set by the system operator in accordance with Schedule 13.3:

(C) the number of occurrences at which reserve (in MW) for a participant at a set of grid exit points is equal to the maximum reserve (in MW) for that set of grid exit points as determined under Schedule 13.3:

(iv) the number of occurrences at which the ramp up rate is equal to the maximum ramp up rate specified in the relevant offer:

(v) the number of occurrences at which the ramp down rate is equal to the maximum ramp down rate as specified in the relevant offer:

(vi) the number of grid exit points at which demand was estimated.

(2) The system operator must use reasonable endeavours to make available on WITS to participants, for each grid injection point and each grid exit point, a time-weighted average of the real time prices for each trading period.

13.91 System operator to use backup procedures if WITS is unavailable

Transmission of information through information system

(1) All information that must be made available by the system operator under clauses 13.89 to 13.96 must be transmitted through the electronic facility contained in the information system.

(2) If WITS the information system is unavailable to make send information available under clauses 13.89 to 13.96, the system operator must follow the backup procedures specified by the WITS market administrator.

(3) The backup procedures referred to in subclause (2) must be specified by the WITS market administrator following consultation with purchasers, generators and the system operator. The market administrator must ensure that there is always a backup procedure notified to purchasers, generators and the system operator.

13.92 Transmission of information through website

(1) The information (if any) received from the system operator under clause 13.90 must be published made available by the market administrator by placing that information on a publicly accessible website.

(2) If the publicly accessible website upon which information is to be published placed under subclause (1) is no longer available, the market administrator is not required to follow any backup procedures, and the market administrator is not required to make the information available on the publicly accessible website at a later time.

13.104 System operator to make information available on WITS to be published

(1) As soon as practicable after the system operator has completed preparing a price-responsive schedule and a non-response schedule, the system operator must make available on WITS publish, for each trading period in the schedule length period,—

(a) the following information in respect of both the price-responsive schedule and the non-response schedule:

(i) forecast prices and forecast reserve prices; and

(ii) scheduled non-dispatch-capable load at each conforming GXP; and
(iii) the aggregate supply curve at each reference point incorporating all offers from generators with offer prices adjusted for forecast marginal location factors; and
(iv) the grid injection points and grid exit points that are disconnected; and
(v) the grid injection points and grid exit points where an infeasibility situation has occurred; and
(vi) the scheduled largest single reserve risk for each island as described in clause 13.59(ix); and
(vii) the scheduled levels of fast instantaneous reserve and sustained instantaneous reserve required in each island as described in clause 13.59(x); and
(viii) the reserve offer stacks for each island as described in clause 13.59(xi); and
(ix) the adjusted reserve offer stacks for each island as described in clause 13.59(xii); and
(x) [Revoked]
(xi) the scheduled HVDC component flows; and
(xii) the scheduled HVDC risk offsets; and
(xiii) the expected near-constraint arc flows; and
(xiv) the expected near-group-constraint arc flows; and
(xv) the group constraint formulas relating to the expected near-group-constraint arc flows; and
(xvi) the expected deficit quantities for energy, fast instantaneous reserve, and sustained instantaneous reserve (if any); and
(xvii) whether the HVDC link is out of service; and
(b) in relation to the price-responsive schedule, the aggregate demand curve at each reference point incorporating the forecast prepared under clause 13.7A(1), and all bids from purchasers with bid prices adjusted for forecast marginal location factors; and
(c) in relation to the non-response schedule, the scheduled frequency keeping units for each island.

(2) Subclause (3) applies to—
(a) each price-responsive schedule prepared under clause 13.62(1)(a):
(b) each non-response schedule prepared under clause 13.62(1)(a).

(3) Despite subclause (1), for each schedule to which this subclause applies, the system operator is not required to publish the information available on WITS set out in subclause (1) for the trading periods covered by—
(a) the price-responsive schedule prepared under clause 13.62(1)(b):
(b) the non-response schedule prepared under clause 13.62(1)(b).

13.105A Information to be made available provided to purchasers, generators, and ancillary service agents

(1) At the same time as the system operator is required to publish information available in accordance with clause 13.104, the system operator must make available on WITS—

(aa) send to each dispatchable load purchaser that has submitted a nominated dispatch bid, information from the current non-response schedule relating to the scheduling
of the dispatchable load purchaser's nominated dispatch bids for the trading periods covered in the schedule length period; and

(a) send to each purchaser information from the current price-responsive schedule relating to the scheduling of the purchaser’s bids for the trading periods covered in the schedule length period; and

(b) send to each generator information from the current price-responsive schedule and non-response schedule relating to the scheduling of the generator's offers for the trading periods covered in the schedule length period; and

(c) send to each ancillary service agent who has submitted a reserve offer for the scheduling period, information from the current price-responsive schedule and non-response schedule relating to the scheduling of the ancillary service agent’s reserve offers for the trading periods covered in the schedule length period.

(2) Subclause (3) applies to—

(a) each price-responsive schedule prepared under clause 13.62(1)(a);

(b) each non-response schedule prepared under clause 13.62(1)(a).

(3) Despite subclause (1), for each schedule to which this subclause applies, the system operator is not required to make available on WITS send the information set out in subclause (1) for the trading periods covered by—

(a) the price-responsive schedule prepared under clause 13.62(1)(b);

(b) the non-response schedule prepared under clause 13.62(1)(b).

13.106 Transmission of information through information system

(1) The information required to be published by the system operator under clauses 13.104 to 13.105A must be transmitted through the electronic facility contained in the information system.

(2) If WITS the information system is unavailable to make send information available under clauses 13.104 to 13.105A, the system operator must follow the backup procedures specified by the WITS manager market administrator.

(3) The backup procedures referred to in subclause (2) must be specified by the WITS manager market administrator following consultation with the system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents. The market administrator must ensure that there is always a backup procedure notified to the system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents.

13.114 Auction information to be transmitted exchanged through WITS information system

(1) Except where specified otherwise in this Part, all information in relation to auctions must be transmitted exchanged through WITS the information system.

(2) If WITS the information system is not available to transmit send information under this clause, the clearing manager must follow the backup procedures specified by the WITS manager market administrator.

(3) The backup procedures referred to in subclause (2) must be specified by the WITS manager market administrator following consultation with generators and the clearing manager.
13.119 Historic load data
By 1100 hours 2 days before each auction, each grid owner must give written notice or use WITS to advise the clearing manager the total load of the preceding year day for the day following the auction.

13.121 Notice of auction and deadline for auction bids
(1) For each auction, by any time up to 1100 hours on the day before the auction, the clearing manager must give written notice or use WITS to advise each generator of the quantity of auction rights available in each time block at the auction to be held the following day and must invite auction bids for those auction rights.
(2) A generator who wishes to bid at an auction must submit auction bids by 0900 hours on the day that the auction is to be held.

13.122 Revising, cancelling and extending auction bids
(1) A generator may revise or cancel an auction bid by giving written notice or through WITS up to 0900 hours on the day of the auction to which the auction bid relates.
(2) Each auction bid is valid for only 1 auction unless the generator expressly states when it makes the auction bid that the auction bid is to remain valid until cancelled.

13.128 Results
By 1100 hours on the day of each auction the clearing manager must give written notice or use WITS to notify—
(a) each generator that has bid at an auction of the outcome of the auction; and
(b) all generators and purchasers of the quantity and price of all successful auction bids made at the auction.

13.129 Authorisation to successful bidders
The clearing manager must give issue an authorisation to each generator, by way of a written notice or through WITS, that secures auction rights at an auction. The authorisation must set out the auction rights the generators secured at the auction and the price payable for them.

13.130 Records
The clearing manager must maintain a complete record for 3 years of all quantities of auction rights offered, all auction bids received, and the prices achieved in each time block at each auction. A generator may require the clearing manager to provide information relating to the generator's auction bids and auction results at any time within that period in writing or through WITS.

13.132 Purpose of the pricing process
The purpose of the pricing process is to achieve an appropriate balance between certainty and accuracy of final prices and final reserve prices for each trading period. As part of the process—
(a) the system operator, the pricing manager, a grid owner, or a generator must take certain steps under this subpart if a provisional price situation or shortage situation exists; and
(b) after any **provisional price situation** is resolved, but before making the **publishing final prices** or **final reserve prices** available on WITS, the pricing manager must make available on WITS **publish interim prices** and **interim reserve prices**; and

(c) if an **error claimant** claims that a **pricing error** has been made, the **pricing manager** must consider the claim and resolve any **pricing error** that has occurred; and

(d) the **pricing manager** must produce **final prices** and send them to the **clearing manager**, who will then use them in the clearing and settlement processes; and

(e) the **pricing manager** must produce **final reserve prices**.

13.135A Notice of scarcity pricing situation

(1) This clause applies if the **pricing manager**, in relation to a **trading period**, gives written notice in accordance with clause 13.144(1) that a **shortage situation** exists.

(2) If this clause applies, the **pricing manager** must determine whether a **scarcity pricing situation** exists in the relevant **trading period**.

(3) An **island scarcity pricing situation** exists for an **island** if the **pricing manager** gives notice that an **island shortage situation** existed and the **input information** or revised data shows that—

(a) for the relevant **trading period**, there is no **binding constraint** in the island (excluding the HVDC link) in which an **island shortage situation** declaration is made; and

(b) for the relevant **trading period**—

(i) the HVDC link is in service and—

(A) if the island in which the **island shortage situation** declaration is made is the South Island, the price at the Benmore node is higher than the price at the Haywards node; or

(B) if the island in which the **island shortage situation** declaration is made is the North Island, the price at the Haywards node is higher than the price at the Benmore node; or

(ii) the HVDC link is out of service.

(4) A **national scarcity pricing situation** exists if the **pricing manager** gives notice that a **national shortage situation** existed and the **input information** or revised data shows that, for the relevant **trading period**,—

(a) there is no **binding constraint** in either island; and

(b) the HVDC link is in service and there is no **binding constraint** on the HVDC link.

(5) If the **pricing manager** determines that a **scarcity pricing situation** exists, the **pricing manager** must—

(a) give **publish** notice on WITS of the **scarcity pricing situation**; and

(b) specify in the notice each **trading period** affected by the **scarcity pricing situation**; and

(c) in relation to each **trading period** affected by the **scarcity pricing situation**, specify in the notice whether the **scarcity pricing situation** is an **island scarcity pricing situation** or a **national scarcity pricing situation**.
13.135B Methodology to prepare interim prices and interim reserve prices if scarcity pricing situation exists

Subject to clause 13.135C, if a scarcity pricing situation exists in a trading period, the pricing manager must—

(a) calculate interim prices and interim reserve prices in the affected island or islands for that trading period in accordance with the methodology set out in Schedule 13.3A; and

(b) make available on WITS publish interim prices and interim reserve prices for the trading period by—

(i) if no provisional price situation is notified, 1200 hours in the following trading day; or

(ii) if a provisional price situation is notified, 2.5 hours after the provisional price situation is resolved.

13.136 Generators to provide half-hour metering information

(1) Using an approved system or by written notice eEach generator must give the relevant grid owner half-hour metering information under clause 13.138 in relation to generating plant that is subject to a dispatch instruction—

(a) that injects electricity directly into a local network or an embedded network; or

(b) if the meter configuration is such that the electricity flows into a local network without first passing through a grid injection point or grid exit point metering installation.

(1A) For the purposes of subclause (1), the relevant grid owner is—

(a) in relation to a generator (other than an embedded generator), the grid owner of the grid to which the generator's generation is connected; and

(b) in relation to a generator that is an embedded generator, the grid owner of the grid to which the local network to which the embedded generator is directly or indirectly connected, is connected.

(2) To avoid doubt, subclause (1) does not apply in respect of—

(a) any unoffered generation; or

(b) electricity supplied from—

(i) an intermittent generating station; or

(ii) a type B industrial co-generating station.

13.137 Generators to provide half-hour metering information for unoffered and intermittent generation and type B industrial co-generation

(1) Using an approved system or by written notice eEach generator must give the relevant grid owner half-hour metering information for—

(a) unoffered generation from a generating station with a point of connection to the grid; and

(b) electricity supplied from an intermittent generating station with a point of connection to the grid; and

(c) electricity supplied from a type B industrial co-generating station with a point of connection to the grid.

(2) To avoid doubt, each generator must give the relevant grid owner the half-hour metering information required under this clause in accordance with the requirements of Part 15 for the collection of the generator's volume information.
If the half-hour metering information is not available, the generator must give the relevant grid owner a reasonable estimate of such data using an approved system or by written notice.

13.138A Dispatchable load purchaser’s half-hour metering information to be adjusted for losses

(1) Using an approved system or by written notice, each dispatchable load purchaser must provide half-hour metering information to the relevant grid owner—
   (a) for each of its dispatch-capable load stations; and
   (b) in accordance with subclause (2).

(2) Each dispatchable load purchaser must provide the half-hour metering information—
   (a) adjusted for losses, if any, relative to the grid exit point at which the dispatchable load purchaser purchases electricity for the dispatch-capable load station; and
   (b) in the manner and form advised by the relevant grid owner; and
   (c) by 0500 hours on a trading day for each trading period of the previous trading day.

(3) To avoid doubt, each dispatchable load purchaser must prepare the half-hour metering information required under this clause in accordance with the requirements of Part 15 for the collection of the dispatchable load purchaser’s volume information.

(4) If the Authority or the system operator requests a copy of the information specified in subclause (2) from a dispatchable load purchaser, the dispatchable load purchaser must comply with the request.

13.141 Pricing manager to use certain input information

(1) The pricing manager must use the following input information:
   (a) for existing generation configuration—
      (i) data specifying the instantaneous MW injection at the grid injection point at the beginning of each trading period for each generating plant and each generating unit that was the subject of offers for that trading period; or
      (ii) if no such data is available, a reasonable estimate of such data:
   (b) for actual demand over the trading period,—
      (i) the demand half-hour metering information described as L\text{MA} below must be calculated as follows:

\[
\begin{align*}
L_{\text{MA}} &= G_{\text{EA}} + L_{\text{MX}} - L_{\text{DCLS}} \text{ (for a grid exit point)} \\
L_{\text{MA}} &= G_{\text{EA}} - L_{\text{MI}} - L_{\text{DCLS}} \text{ (for a grid injection point)} \\
L_{\text{MA}} &= L_{\text{MX}} - L_{\text{DCLS}} - U_{\text{IGEA}} \text{ (for an intermittent generating station with a point of connection to the grid, and/or unoffered generation from a generating station with a point of connection to the grid, and/or a type B industrial co-generating station with a point of connection to the grid)}
\end{align*}
\]

where

\( L_{\text{MA}} \) is the adjusted quantity of electricity measured in MWh by a metering installation at a grid exit point or grid injection point

\( L_{\text{MX}} \) is the unadjusted half-hour metering information for the quantity of electricity measured in MWh at a grid exit point
L_{MI} \text{ is the unadjusted half-hour metering information for the quantity of electricity measured in MWh at a grid injection point}

L_{DCLS} \text{ is the adjusted half-hour metering information for the quantity of electricity measured in MWh used by a dispatch-capable load station for the trading periods that the system operator listed under clause 13.138B}

G_{EA} \text{ is the adjusted half-hour metering information given to the relevant grid owner under clause 13.136}

UIG_{EA} \text{ is the information given to the relevant grid owner under clause 13.137:}

(ii) if any of the half-hour metering information is not available, an initial estimate for each grid exit point or grid injection point:

(iii) to avoid doubt, each grid owner must, using an approved system, provide the half-hour metering information to the pricing manager required under this clause in accordance with Part 15 for the collection of that grid owner’s volume information:

(c) the final offers for each trading period submitted by generators and provided to the pricing manager by the system operator in accordance with clause 13.63:

(ca) the final nominated dispatch bid for each dispatch-capable load station (other than a dispatch-capable load station for which the final nominated bid for the trading period was a nominated non-dispatch bid) dispatched in each trading period that was provided to the pricing manager by the system operator in accordance with clause 13.63:

(d) the final reserve offers for each such trading period as given by ancillary service agents in accordance with clauses 13.37 to 13.54:

(e) the final information provided to the system operator by a grid owner under clauses 13.29 to 13.34 for each trading period that the system operator notifies in accordance with clause 13.63.

(1AA) The pricing manager must remove all offers from the following participants from the information specified in subclause (1)(c) before using it in the pricing process:

(a) intermittent generators; and

(b) type B co-generators.

(1A) Each grid owner must give the pricing manager the information the pricing manager is required to use under subclause (1)(a)—

(a) by 0730 hours on each trading day; and

(b) for each trading period of the previous trading day; and

(c) in the manner and form agreed by the pricing manager and each grid owner.

(2) Each grid owner must give the information required by subclause (1)(b) to the pricing manager by 0730 hours on a trading day for each trading period of the previous trading day. Each grid owner must provide this information in the form specified by the pricing manager.

(3) The pricing manager must make available on WITS, and available to the public at no cost on the WITS manager’s website, publish the information by 1000 hours on a trading day for each trading period of the previous trading day.

(4) If the pricing manager receives revised demand half-hour metering information in accordance with clauses 13.146(1) and 13.154(1A)(b), and if the revised information
resolves a **provisional price situation**, the **pricing manager** must make available on **WITS**, and available to the public at no cost on the **WITS manager's website**. Publish the revised demand **half-hour metering information** no later than the time at which it is required to make available on **WITS**—**publish interim prices** and **interim reserve prices**.

(5) If the **pricing manager** receives revised information after it has made **published** information available in accordance with subclause (3), the **pricing manager** must replace the information previously made available **published** with the revised information by replacing the previously **published** information with the revised information.

13.142 Pricing manager to make available on WITS—publish interim prices unless provisional price situation or shortage situation notified

(1) The **pricing manager** must implement the process set out in clauses 13.143 to 13.185 and resolve the **provisional price situation** or **shortage situation** if, by 1000 hours on a **trading day**, 1 of the following notices has been **published** for the previous **trading day**:

- a notice published by a **grid owner** has given a **written notice**, in accordance with clause 13.143, which specifies that a **SCADA situation** exists;
- a notice published by the **pricing manager** has given a **written notice**, in accordance with clause 13.144(1), which specifies that an **infeasibility situation** or a **metering situation** or a **high spring washer price situation** or a **shortage situation** exists.

(2) However, if by 1000 hours on a **trading day** a notice specified in subclause (1) has not been **published** for the previous **trading day**, the **pricing manager** must make available on **WITS**—**publish interim prices** and **interim reserve prices** for the previous **trading day** by 1200 hours.

13.143 Grid owners to give written notice of notify SCADA situation

(1) If a **grid owner** gives any **input information** in accordance with clause 13.141 to the **pricing manager**, the **grid owner** must—

- give written notice to affected participants that it has given the **pricing manager input information**; and
- specify in the notice whether the **input information** yields a **SCADA situation**, and if so each **trading period** affected; and
- give details in the notice of the relevant **grid exit points** and **grid injection points** for which the **SCADA situation** exists.

(2) A **grid owner** must give the notice required by subclause (1)(a) by 0730 hours on the day on which it gives the relevant **input information**.

(3) Despite subclause (2), the **grid owner** may give further **written notices to affected participants** advising that the **grid owner** has found that a **SCADA situation** exists and the **trading periods** that are affected by it.

(4) A **grid owner** must give each **written notice published** in accordance with subclause (3) no later than 0900 hours on the same day that it gave notice under subclause (1)(a).
13.144 Pricing manager to give notice of infeasibility situation, metering situation, high spring washer price situation, or shortage situation

(1) Subject to subclause (2), if the pricing manager receives input information that yields an infeasibility situation, or a metering situation, or a high spring washer price situation, or receives notice of a shortage situation in accordance with clause 5(1A) of Technical Code B of Schedule 8.3, the pricing manager must, no later than 0900 hours on the day that the pricing manager receives the input information or notice,—

(a) give written notice to affected participants of the infeasibility situation, or metering situation, or high spring washer price situation, or shortage situation; and

(b) specify in the notice each trading period affected by the infeasibility situation, or metering situation, or high spring washer price situation, or shortage situation; and

(c) in relation to each trading period affected by a high spring washer price situation, specify in the notice each transmission security constraint that has bound in the relevant trading period or trading periods; and

(d) in relation to each trading period affected by a shortage situation, specify in the notice whether the shortage situation is an island shortage situation or a national shortage situation.

(2) The pricing manager must not give written notice of a high spring washer price situation or shortage situation in accordance with subclause (1) in relation to a trading period if an infeasibility situation, or a metering situation, or a SCADA situation exists in that trading period and has not been resolved.

13.145 Grid owner to give written notice that estimated data given

If a grid owner gives the pricing manager estimated input information in accordance with clauses 13.141(1)(a)(ii) or (b)(ii), the grid owner must, by 0730 hours on the day the relevant input information is required by clause 13.141—

(a) give written notice to affected participants of any input information that is estimated; and

(b) specify in the notice whether the estimated information relates to SCADA or half-hour metering information; and

(c) give details in the notice of the grid exit points and grid injection points to which the estimated information relates; and

(d) specify in the notice whether the estimated information relates to a dispatch capable load station or a type B industrial co-generating station; and

(e) specify in the notice the trading periods for which the input information is estimated for each relevant grid exit point, grid injection point, and dispatch capable load station.

13.146 Requirements if provisional price situation or shortage situation exists

(1) If notice is given by—

(a) a grid owner to the pricing manager of a SCADA situation in accordance with clause 13.143; or
(b) the **pricing manager** of a **metering situation** in accordance with clause 13.144(1); or

(c) the **pricing manager** of an **infeasibility situation** in accordance with clause 13.144(1)—

the relevant **grid owner**, and, in the case of an **infeasibility situation**, the **system operator**, must exercise reasonable endeavours to resolve the **provisional price situation** and to provide revised data to the **pricing manager** using an **approved system**.

(2) If notice is given of a **high spring washer price situation** in accordance with clause 13.144(1), the **system operator** must apply the **high spring washer price relaxation factor** in accordance with the **high spring washer price situation methodology** and provide revised data to the **pricing manager** using an **approved system**.

(2A) If the **pricing manager** gives notice of a **shortage situation** in accordance with clause 13.144(1), the **pricing manager** must determine whether a **scarcity pricing situation** exists in accordance with clause 13.135A and, if a **scarcity pricing situation** does exist, calculate **interim prices** and **interim reserve prices** in accordance with clause 13.135B.

(3) The revised data required by subclauses (1) and (2) must be provided to the **pricing manager**—

(a) if the **provisional price situation** arose on a **business day**, by 1000 hours on that day; and

(b) if the **provisional price situation** arose on a day other than a **business day**, by 1200 hours on the 2\textsuperscript{nd} **business day** after the **provisional price situation** arose.

(4) If a **generator** or a **dispatchable load purchaser** does not give supply **half-hour metering information** to a **grid owner** in accordance with clauses 13.136 to 13.140, and the **pricing manager** has notified a **metering situation** in accordance with clause 13.144(1), the **generator** or the **dispatchable load purchaser** must use reasonable endeavours to assist the **grid owner** to resolve the **provisional price situation**.

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**13.147 Revised data to be accompanied by notice**

(1) This clause applies to—

(a) a **grid owner**; and

(b) [Revoked]

(c) the **system operator**.

(d) [Revoked]

(2) If a **participant** to which this clause applies gives revised data to the **pricing manager** under clause 13.146, the **participant** must—

(a) **give written publish** notice to affected participants specifying that it has given revised data; and

(b) specify in the notice the revisions that have been made; and

(c) in the case of revised data given in relation to a **SCADA situation**, state in the notice whether a **SCADA situation** continues to exist; and

(d) in the case of revised data given in relation to a **high spring washer price situation**, state in the notice whether the **high spring washer price relaxation factor** has been applied.

(3) A **participant** to which this clause applies must comply with subclause (2) within the timeframes specified in clause 13.146(3) as if references to the revised data in clause 13.146(3) are references to a notice under this clause.
13.149 Pricing manager to make available on WITS publish provisional prices and provisional reserve prices and give written notice of provisional price situation if revised data and notice not given in relation to provisional price situation arising on business day

(1) This clause applies if—
   (a) a notice of a **provisional price situation** is given on a **business day**; and
   (b) a **participant** that is listed in clause 13.147(1)—
      (i) does not comply with the timeframes specified in clause 13.146(3); or
      (ii) does not comply with the timeframes specified in clause 13.147(3).

(2) If this clause applies, the **pricing manager** must—
   (a) by 1200 hours on that day, **give** written notice to affected participants of the **provisional price situation** and each **trading period** affected; and
   (b) by 1200 hours on that day, **make available on** WITS publish provisional prices and **provisional reserve prices**; and
   (c) by 0900 hours on the following day, inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213.

13.150 Pricing manager to make available on WITS publish provisional prices and provisional reserve prices and give written notice of provisional price situation if revised data and notice not given in relation to provisional price situation arising on day other than business day

(1) This clause applies if—
   (a) a notice of a **provisional price situation** is given on a day other than a **business day**; and
   (b) a **participant** that is listed in clause 13.147(1),—
      (i) does not comply with the timeframes in clause 13.146(3); or
      (ii) does not comply with the timeframes in clause 13.147(3).

(2) If this clause applies, the **pricing manager** must—
   (a) by 1000 hours on the day that the notice of a **provisional price situation** was given, **give** written notice to affected participants of the **provisional price situation** and each **trading period** affected; and
   (b) by 1000 hours on that day, **make available on** WITS publish provisional prices and **provisional reserve prices**; and
   (c) by 0900 hours on the following day, inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213.

13.152 Pricing manager to make available on WITS publish interim prices and interim reserve prices if revised data resolves provisional price situation

(1) This clause applies if a **participant** that is listed in clause 13.147(1)—
   (a) gives revised data in accordance with clause 13.146 (that does not itself give rise to a **provisional price situation**); or
   (b) gives a written **publishes** a notice in accordance with clause 13.147.

(2) If this clause applies, the **pricing manager** must make available on WITS publish interim prices and **interim reserve prices** for each **trading period** of the previous trading day.
(3) The **pricing manager** must make available on WITS publish the **interim prices** and **interim reserve prices** by 1200 hours on the day that the revised data and notice were required to be given.

13.153 Revised data gives rise to provisional price situation
If revised data provided in accordance with clause 13.146 gives rise to a **provisional price situation**, the **pricing manager** must make available on WITS publish provisional prices and **provisional reserve prices** in accordance with clauses 13.149 and 13.150, as if no data had been received.

13.154 Grid owner, generators, dispatchable load purchasers, and system operator to give revised data if provisional prices and provisional reserve prices have been published
(1) This clause applies if the **pricing manager** makes publishes provisional prices and **provisional reserve prices** available under clause 13.149 or 13.150.
(1A) If **provisional prices** and **provisional reserve prices** are made available on WITS published in relation to—
(a) an **infeasibility situation** or a **SCADA situation**, the **grid owner** and, in the case of an **infeasibility situation**, the **system operator**, must use reasonable endeavours to resolve the **provisional price situation** and provide revised data to the **pricing manager** using an **approved system**; or
(b) a **metering situation**, the **grid owner** or the **generator** or the **dispatchable load purchaser** (as the case may be) must provide revised **metering information** in accordance with clause 13.166; or
(c) a **high spring washer price situation**, the **system operator** must apply the **high spring washer price relaxation factor** in accordance with the **high spring washer price situation methodology** and use reasonable endeavours to provide revised data to the **pricing manager** using an **approved system**.
(2) The revised data required by subclause (1A) must be provided to the **pricing manager** by 1200 hours on the 2\textsuperscript{nd} **business day** following after the **pricing manager** makes **publication** of the revision **provisional prices** and **provisional reserve prices** available on WITS.

13.155 Revised data to be accompanied by written notice
If a **participant** that is listed in clause 13.147(1) gives revised data in accordance with clause 13.154 to the **pricing manager**, the **participant** must, by the time prescribed by that clause for giving revised data,—
(a) give written **publish** notice to affected **participants** that revised data has been given; and
(b) specify in the notice the revisions that have been made; and
(c) in the case of revised data given in relation to a **metering situation** or a **SCADA situation**, state in the notice whether a **metering situation** or a **SCADA situation** continues to exist; and affected
(d) in the case of revised data given in relation to a **high spring washer price situation**, if the **high spring washer price situation relaxation factor** has been applied, state in the notice that the factor has been applied.

13.156 Pricing manager to make available on WITS publish interim prices after following publication of provisional prices and provisional reserve prices are made available
unless further provisional price situation arises and give written notice that an
infeasibility situation or high spring washer price situation exists

(1) Subject to subclause (2), if the pricing manager—
(a) does not receive revised data in accordance with clause 13.154 and notice in
accordance with clause 13.155 in relation to a provisional price situation (other
than a high spring washer price situation), the pricing manager must make
available on WITS publish interim prices and interim reserve prices for all
trading periods of the relevant trading day in accordance with clauses 13.163 and
13.164; or
(b) does not receive revised data in accordance with clause 13.154 and notice in
accordance with clause 13.155 in relation to a high spring washer price situation,
the pricing manager must, by 1400 hours on the 2nd business day after the
provisional prices and provisional reserve prices were made available on WITS
published, make available on WITS publish interim prices and interim reserve
prices for all trading periods of the relevant trading day as if the high spring
washer price situation did not exist; or
(c) receives revised data in accordance with clause 13.154 (that does not itself give rise
to a provisional price situation) and notice in accordance with clause 13.155, the
pricing manager must, by 1400 hours on the 2nd business day after the
provisional prices and provisional reserve prices were made available on WITS
published, make available on WITS publish interim prices and interim reserve
prices for all trading periods of the relevant trading day; or
(d) receives revised data in accordance with clause 13.154 and notice in accordance with
clause 13.155 and an infeasibility situation arises from that data, the pricing
manager must, by 1400 hours on the 2nd business day after the provisional
prices and provisional reserve prices were made available on WITS published, give
written notice to affected participants that an infeasibility situation exists,
specifying in the notice each trading period affected by the infeasibility situation;
or
(e) receives revised data in accordance with clause 13.154 and notice in accordance with
clause 13.155 and a high spring washer price situation arises from that data, the
pricing manager must, by 1400 hours on the 2nd business day after the provisional
prices and provisional reserve prices were made available on WITS published, give
written notice to affected participants that a high spring washer price situation
exists, specifying in the notice—
(i) each trading period affected by the high spring washer price situation; and
(ii) each transmission security constraint that has bound in the relevant trading
day or trading periods.

(2) The pricing manager must not give written notice of a high spring washer price
situation in accordance with subclause (1)(e) in relation to a trading period if—
(a) an infeasibility situation exists in that trading period and it has not been resolved;
or
(b) the pricing manager has previously given written notice that a high spring washer
price situation exists in that trading period.
13.157 Requirements if infeasibility situation or high spring washer price situation exists

(1) If the pricing manager gives notice of an infeasibility situation in accordance with clause 13.156(1)(d), the relevant grid owner and the system operator must, by 1600 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS published, exercise reasonable endeavours to resolve the provisional price situation and provide revised data to the pricing manager using an approved system.

(2) If the pricing manager gives notice of a high spring washer price situation in accordance with clause 13.156(1)(e), the system operator must, by 1600 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS published, apply the high spring washer price relaxation factor in accordance with the high spring washer price situation methodology and provide revised data to the pricing manager using an approved system.

13.158 Revised data to be accompanied by written notice

If a grid owner or the system operator gives revised data to the pricing manager in accordance with clause 13.157, the grid owner or system operator (as the case may be) must, by the time prescribed by that clause for giving revised data,—

(a) give written publish notice to affected participants that revised data has been given; and

(b) specify in the notice the revisions that have been made; and

(c) in the case of revised data given in relation to an infeasibility situation, state in the notice whether the infeasibility situation has been resolved; and

(d) in the case of revised data given in relation to a high spring washer price situation, if the high spring washer price situation relaxation factor has been applied, state in the notice that the factor has been applied.

13.159 Pricing manager to make available on WITS-publish interim prices or give written publish notice that high spring washer price situation exists

Subject to clause 13.160, if the pricing manager—

(a) receives revised data in accordance with clause 13.157 and notice in accordance with clause 13.158, the pricing manager must,—

(i) if the revised data does not itself give rise to a provisional price situation, by 1800 hours on the 2nd business day after the provisional prices and provisional reserve prices were published, make available on WITS publish interim prices and interim reserve prices for all trading periods of the relevant trading day; or

(ii) if an infeasibility situation arises from that data, make available on WITS publish interim prices and interim reserve prices in accordance with clauses 13.163 and 13.164; or

(iii) if a high spring washer price situation arises from that data, by 1800 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS published, give written publish notice to affected participants that a high spring washer price situation exists, specifying in the notice—
(A) each trading period affected by the high spring washer price situation; and
(B) each transmission security constraint that has bound in the relevant trading period or trading periods; and

(b) does not receive revised data in accordance with clause 13.157 and does not receive a written notice in accordance with clause 13.158,—
(i) in relation to an infeasibility situation, the pricing manager must make available on WITS publish interim prices and interim reserve prices in accordance with clauses 13.163 and 13.164; or
(ii) in relation to a high spring washer price situation, the pricing manager must make available on WITS publish interim prices and interim reserve prices by 1800 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS published, as if the high spring washer price situation did not exist.

13.161 System operator to apply high spring washer price relaxation factor and give notice
(1) If the pricing manager gives electronic written notice of a high spring washer price situation in accordance with clause 13.159(a)(iii), the system operator must, by 1000 hours on the 3rd business day after the provisional prices and provisional reserve prices were made available on WITS published,—
(a) apply the high spring washer price relaxation factor in accordance with the high spring washer price situation methodology; and
(b) exercise reasonable endeavours to provide revised data to the pricing manager using an approved system.

(2) If the system operator gives revised data to the pricing manager in accordance with subclause (1), the system operator must, by the time prescribed by that subclause for giving revised data,—
(a) give written notice to affected participants that the revised data has been given; and
(b) specify in the notice the revisions that have been made; and
(c) if the high spring washer price relaxation factor has been applied, state in the notice that the factor has been applied.

13.162 Pricing manager to publish make interim prices available on WITS
If the pricing manager—
(a) receives revised data in accordance with clause 13.161(1) and notice in accordance with clause 13.161(2), the pricing manager must, publish by 1200 hours on the 3rd business day after the provisional prices and provisional reserve prices were made available on WITS published, make available on WITS publish interim prices and interim reserve prices for all trading periods of the relevant trading day; or
(b) does not receive revised data in accordance with clause 13.161(1) and does not receive a notice in accordance with clause 13.161(2), the pricing manager must, by 1200 hours on the 3rd business day after the provisional or provisional reserve price was made available on WITS published, make available on WITS publish interim prices and interim reserve prices for all trading periods of the relevant trading day as if the high spring washer price situation did not exist.
13.163 Revised data cannot be given or revised data gives rise to provisional price situation (other than high spring washer price situation)

If clause 13.156(1)(a) applies, or the revised data received in accordance with clause 13.157(1) does not resolve an infeasibility situation or gives rise to a provisional price situation (other than a high spring washer price situation), the pricing manager must make available on WITS publish interim prices and interim reserve prices and must give written notice to generators and purchasers—

(a) for each trading period not affected by a provisional price situation; and

(b) on the basis of the information given to it under clause 13.154; and

(c) by 1800 hours of the 2nd business day after it makes available on WITS publishes provisional prices and provisional reserve prices.

13.164 If provisional price situation (other than high spring washer price situation) continues

If clause 13.156(1)(a) applies, or the revised data received in accordance with clause 13.157(1) does not resolve an infeasibility situation or gives rise to a provisional price situation (other than a high spring washer price situation), the pricing manager must, for each affected trading period,—

(a) no later than the time at which the pricing manager would be required to make publish interim prices available under clause 13.163, give a written notice to affected participants that it cannot calculate interim prices and interim reserve prices, specifying the trading periods affected; and

(b) on the basis of the information given to the pricing manager under clause 13.154, calculate and make available on WITS publish interim prices for all grid injection points and all net grid exit points for each affected trading period by—

(i) assigning a price to all net grid injection points for each affected trading period equal to the highest price at the point that the loss adjusted demand intersects with the offer stack; and

(ii) assigning a price to all net grid exit points equal to 1.05 times the price calculated for all grid injection points under subparagraph (i)—

by 1800 hours on the 2nd business day after it publishes makes available on WITS provisional prices and provisional reserve prices; and

(c) calculate and make available on WITS interim reserve prices by taking the mean of the relevant final reserve prices of the corresponding day in each of the 4 previous weeks, by 1800 hours on the 2nd business day after it publishes makes provisional prices and provisional reserve prices; and

(d) give written notice to affected participants of all interim prices and interim reserve prices by 1800 hours on the 2nd business day after it makes available on WITS publishes provisional prices and provisional reserve prices.

13.165 Authority notified if provisional price situation not resolved

(1) If a grid owner or the system operator receives notice of an unresolved provisional price situation in accordance with clause 13.164, the grid owner or system operator (as the case may be) must immediately give written notice to notify the Authority of—

(a) how the unresolved provisional price situation arose; and
(b) the steps taken in attempting to resolve the **provisional price situation**; and
(c) the reasons for the inability of the **grid owner** or **system operator** (as the case may be) to resolve the **provisional price situation**.

(2) As soon as it receives a notice given under subclause (1), the **Authority** must consider the unresolved **provisional price situation** and urgently address the matters raised in the notice.

13.166A Pricing manager to recalculate and make available on WITS publish interim prices if infeasibility situation caused by shortage of instantaneous reserve

(1) If an **infeasibility situation** that has been resolved under this subpart was caused by a shortage of **instantaneous reserve**, the **pricing manager** must recalculate and **make available on WITS publish interim prices** for the relevant **trading period** by adding a virtual provider of **fast instantaneous reserve** and **sustained instantaneous reserve**, at the price as specified in subclause (2), that provides sufficient **fast instantaneous reserve** and **sustained instantaneous reserve** so that prices for **fast instantaneous reserve** and **sustained instantaneous reserve** do not exceed that price.

13.167 Pricing manager to make available on WITS publish interim prices

The **pricing manager** must **make available on WITS publish interim prices and interim reserve prices**—

(a) when required to do so by clauses 13.142, 13.152, 13.156(1), 13.159, 13.162, 13.163 or 13.164, by 1200 on each **trading day** for the previous **trading day**; and

(b) when required to do so by clause 13.135B; and

(c) before **making available on WITS publishing final prices or final reserve prices**.

13.168 When pricing error may be claimed

Once the **pricing manager** has **made available on WITS, interim prices and interim reserve prices**, an **error claimant** may claim that the prices contain a **pricing error**.

13.170 Method and timing for claiming pricing error has occurred

To claim that a **pricing error** has occurred, an **error claimant** must—

(a) complete the form set out in Form 9 of Schedule 13.1; and

(b) include sufficient information in the form to demonstrate that the **error claimant** (other than an **error claimant** described in clause 13.169(2)) has been materially affected by the **pricing error**; and

(c) give email the completed form to an email address notified by the **pricing manager** for that purpose; and

(d) comply with paragraphs (a) to (c) no later than 1200 on the 1st **business day** following the **trading day** on which the **pricing manager** **made available on WITS published the interim price or interim reserve price** that contains the **pricing error**.
13.171 Pricing manager must make available on WITS publish final prices if no pricing error claimed

(1) This clause applies if, by 1200 on the 1st business day following the trading day on which the pricing manager made available on WITS published the interim price or interim reserve price, no pricing error is claimed in respect of the interim prices or interim reserve prices.

(2) The pricing manager must make available on WITS publish the interim prices as final prices, and interim reserve prices as final reserve prices, by 1400 hours on the 1st business day following the trading day on which the pricing manager made available on WITS published the interim prices or interim reserve prices.

13.172 Effect of pricing error being claimed

If an error claimant claims that a pricing error is contained in either interim prices or interim reserve prices, the pricing manager must not make available on WITS publish final prices or final reserve prices until the pricing manager has implemented the Authority's decision in accordance with clause 13.177.

13.173 Process when pricing error claimed

If the pricing manager receives a claim that an error claimant considers that a pricing error has occurred, the pricing manager must—

(a) check that sufficient information is included in the form as required under clause 13.170; and

(b) confirm to the error claimant that it has received the pricing error claim; and

(c) by 1400 hours on the 1st business day following the trading day on which the pricing manager made available on WITS published the interim prices or interim reserve prices in respect of which the pricing error has been claimed, make available on WITS publish a written notice advising—

(i) that a pricing error has been claimed; and

(ii) the name of the error claimant; and

(iii) the reason for the error claimant believing that a pricing error has occurred; and

(iv) the trading periods that are claimed to have been affected by the pricing error; and

(d) request that the error claimant, a participant, or the Authority, provide the pricing manager with any additional information that the pricing manager reasonably requires to determine whether a pricing error has occurred; and

(e) provide the Authority with a copy of all information it has received in relation to the pricing error that has been claimed; and

(f) determine whether it agrees that a pricing error has occurred.

13.176 Pricing manager to give written publish notice

As soon as practicable after the Authority has notified the pricing manager of its decision under clause 13.175, the pricing manager must publish a give a written notice to affected participants specifying—

(a) the name of the error claimant; and

(b) the reason for the error claimant claiming that a pricing error has occurred; and
(c) the trading periods that are claimed to have been affected by the pricing error; and
(d) the Authority's decision made under clause 13.175; and
(e) the Authority's reasons for its decision under clause 13.175; and:
(f) if the Authority decided that a pricing error had occurred, any actions it has directed be taken to correct the pricing error.

13.177 Pricing manager to implement Authority's decision

(1) If the Authority decides that a pricing error has occurred, the pricing manager must—
(a) take any action directed by the Authority under clause 13.175(c)(i) to correct the pricing error; and
(b) give a written direction to a participant to take any action notified required by the Authority under clause 13.175(c)(ii) to correct the pricing error; and
(c) once those actions have been completed, make available on WITS publish recalculated interim prices and interim reserve prices, using any updated metering information.

(2) If the Authority decides that a pricing error has not occurred, the pricing manager must make available on WITS publish the interim prices and interim reserve prices as final prices and final reserve prices.

13.178 Effect of republishing interim prices

If the pricing manager is required to make available on WITS publish recalculated interim prices and interim reserve prices in accordance with clause 13.177(1)(c)—
(a) the pricing manager must do so by following the methodology required under clauses 13.135 to 13.179; and
(b) a further pricing error may be claimed in respect of the republished recalculated interim prices and interim reserve prices made available on WITS.

13.179 Timing for resolution of pricing error claim process

The pricing manager and the Authority must make reasonable endeavours to ensure that, by 1400 hours on the 2nd business day after the relevant pricing error was claimed, but at least 2 hours after the pricing manager gives publishes the notice under clause 13.176, the pricing manager—
(a) makes available recalculated publishes interim prices and interim reserve prices in accordance with clause 13.177(1)(c); or
(b) makes available publishes final prices and final reserve prices in accordance with clause 13.177(2).

13.180 Actions Authority may take to resolve pricing error

(1) To correct a pricing error, the actions that the Authority may take, or that the Authority may direct the pricing manager to take, include—
(a) delaying the availability the publication of interim prices, interim reserve prices, final prices and final reserve prices under clause 13.184, if the Authority considers that is necessary to allow time for the pricing error to be investigated or corrected; or
(b) giving written directions to any participant to act in a manner that will, in the Authority’s opinion, correct or assist in correcting the pricing error.

(2) However, to avoid any doubt, in resolving a pricing error, the Authority must not—

(a) act inconsistently with this Code, the Act, or any other law; or

(b) require any other participant to act inconsistently with this Code, the Act, or any other law.

13.181 Obligation to comply with pricing manager

(1) If the pricing manager asks a participant or the Authority to provide information in accordance with clause 13.173(d), the participant or the Authority must provide the pricing manager with the requested information in writing, within the reasonable timeframe advised by the pricing manager.

(2) Each participant must comply promptly with any direction given by the pricing manager in accordance with clause 13.175(c)(ii).

(3) To avoid doubt, if an error claimant does not provide the pricing manager with sufficient information to support its claim that a pricing error has occurred, and fails to provide additional information when requested under clause 13.173(d) the pricing manager may recommend under clause 13.174(b) that the Authority not uphold the claim.

13.182 No pricing errors notified after final prices calculated

(1) An error claimant may only claim that a pricing error has occurred in respect of interim prices or interim reserve prices.

(2) Once the pricing manager has made available on WITS final prices or final reserve prices are published, no further pricing errors can be claimed in respect of those prices.

13.183 Recalculation Republication of final prices

Unless directed to do so by the Authority under clause 5.2, the pricing manager must not make available on WITS republish a recalculated the final price or final reserve price for any trading period despite the fact that the final price or final reserve price may contain an error.

13.184 Authority may order delay of publication of final prices

Despite clauses 13.135 to 13.191 the Authority may give a written direction to the pricing manager to delay making order that the publication of interim prices, interim reserve prices, final prices, or final reserve prices available on WITS be delayed.

13.185 Final prices for more than 1 trading day

If the pricing manager is required to make available on WITS publish 1 or more of the following prices for more than 1 trading day at a time, the pricing manager’s publishing deadline for making the price or prices available on WITS is extended by 2 hours for each trading day:

(a) interim prices:

(b) interim reserve prices:

(c) final prices:

(d) final reserve prices.
13.189A Pricing manager to give clearing manager information about dispatch-capable load station from schedule of final prices

(1) The pricing manager must give the clearing manager information about the quantity of electricity scheduled in the schedule of final prices for each dispatch-capable load station for each trading period that is both—
   (a) a trading period for which a nominated dispatch bid was submitted for the dispatch-capable load station; and
   (b) a trading period in the billing period that is immediately before the billing period in which the information must be provided under subclause (2).

(2) The pricing manager must provide the information by 1600 hours on the 7th business day of each billing period through WITS.

13.190 All information and notices to be unconditional and, final and transmitted by information system

(1) All information and every notice to be given under clauses 13.135 to 13.191 must be published through the information system.

(2) Except as provided for in this Code, participants may treat all any such information and notices given under clauses 13.135 to 13.191 as final.

13.191 Backup procedures if WITS or approved system information system is unavailable

(1) If WITS or the approved system information system is unavailable to give or make information available send information under clauses 13.135 to 13.191, each grid owner and the pricing manager must follow the backup procedures specified by the WITS manager.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager following consultation with generators, purchasers, ancillary service agents, the grid owners and the pricing manager.

(3) The market administrator must ensure that there is always a backup procedure notified to all generators, purchasers, ancillary service agents, grid owners and the pricing manager.

13.199 Clearing manager to make available on WITS publish details of constrained off amounts

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

(a) the constrained off amounts calculated in accordance with clauses 13.194 to 13.196:

(b) the generator or dispatched purchaser (as the case may be) that was constrained off:

(c) the applicable grid injection point, or grid exit point, or block dispatch group, or station dispatch group.

13.200 Authority, generators and purchasers have rights to constrained off information

(1) In addition to the information made available published by the clearing manager under clause 13.199, a generator or purchaser who reasonably believes it was adversely
affected by a constrained off situation occurring, or the Authority, may request information from the system operator about the cause of the constrained off situation.

(2) The system operator must comply with any reasonable request made for such information provided that the information does not include any information that is confidential in respect of any other generator or purchaser.

13.206 Time frame for calculating constrained on amounts
The clearing manager must calculate constrained on amounts—
(a) by 1600 hours on the 8th business day of each billing period for the previous billing period in accordance with clauses 13.204 and 13.205; or
(b) if publication of final prices is delayed for any trading period in the relevant billing period, the constrained on amounts calculated in accordance with clauses 13.204 and 13.205 are published later than 1600 hours on the 6th business day of the month following the relevant billing period, 1 business day after all final prices for the billing period are made available on WITS published.

13.208 Clearing manager to make available on WITS publish details of constrained on amounts
The clearing manager must, at the time specified in clause 13.206, make available on WITS publish the details of constrained on amounts 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:
(a) the aggregate constrained on amounts calculated under clauses 13.204 and 13.205:
(b) the generator, ancillary service agent, or dispatched purchaser (as the case may be) that was constrained on:
(c) the applicable grid injection point, grid exit point, block dispatch group, or station dispatch group.

13.209 Authority, generators, ancillary service agents, and purchasers have rights to constrained on information
(1) In addition to the information made available published by the clearing manager under clause 13.208, the Authority, or a generator, ancillary service agent, or purchaser who reasonably believes it was adversely affected by a constrained on situation occurring, may request information from the system operator about the cause of the constrained on situation.
(2) The system operator must comply with any reasonable request for such information except that the information must not include any information that is confidential in respect of any other generator, ancillary service agent, or purchaser.

13.210 Transmission of information through information system
Information sent to generators, ancillary service agents, or purchasers by the clearing manager under clauses 13.199 and 13.208 must be transmitted through the electronic facility contained in the information system.
13.211 Backup procedures if WITS information system is unavailable

(1) If the WITS information system is unavailable to send information under clauses 13.199 and 13.208, the clearing manager must follow the backup procedures specified by the WITS manager/market administrator from time to time.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager/market administrator following consultation with generators, ancillary service agents, purchasers and the clearing manager. The market administrator must ensure that there is always a backup procedure notified to generators, ancillary service agents, purchasers and the clearing manager.

13.213 Daily reports

(1) On each trading day the pricing manager must provide the market administrator with a written report for the trading periods beginning at 0700 hours on the previous trading day and ending with the trading period beginning at 0630 hours on the trading day the report is due to be given, specifying—
   (a) any provisional prices made available on WITSpublished; and
   (b) any pricing errors claimed; and
   (c) any situation where the pricing manager believes, on reasonable grounds, that it or another participant has breached this Code.

(2) In relation to each alleged breach the report must give details of—
   (a) occasions when prices were or will be made available on WITSpublished late and whether the delay was caused by the pricing manager; and
   (b) the time at which the alleged breach took place; and
   (c) the nature of the alleged breach, including details of the person alleged to be in breach and any generator or purchaser believed to be affected by the alleged breach; and
   (d) the reason for the alleged breach, if the pricing manager is aware of the reason.

13.216 Daily situation report

On the day after following the pricing manager made available on WITS publication of final prices and final reserve prices in respect of the trading day to which the published prices relate, the pricing manager must give the market administrator a report containing—

(a) a statement of whether flows on any branches were at their maximum capacity and each trading period affected; and
(b) a statement of whether the status of circulating HVDC link and branch flows was abnormal and each trading period affected.

13.218 Parties required to submit information

The following parties to risk management contracts are required to submit the information specified in clauses 13.219, 13.222 and 13.223 using an approved system:

(a) the seller, if the seller is a participant; or
(b) the buyer, if the buyer is a participant and the seller is not a participant.
13.219 Information that must be submitted

(1) The following information must be submitted to the approved system information system in relation to every options contract:
   (a) the trade date:
   (b) the effective date:
   (c) the end date:
   (d) the quantity.

(2) The following information must be submitted to the approved system information system in relation to each contract for differences or fixed-price physical supply contract:
   (a) whether the contract is a contract for differences or a fixed-price physical supply contract:
   (b) the trade date:
   (c) the effective date:
   (d) the end date:
   (e) the quantity:
   (f) whether or not the contract applies to all trading periods within its term:
   (g) whether there is an adjustment clause:
   (h) whether there is a force majeure clause:
   (i) whether there is a suspension clause:
   (j) whether there are any other clauses providing for the pass-through of certain costs, levies or tax or some form of carbon-related cost.

(3) In addition to the information that must be submitted in accordance with subclause (2), the following information must be submitted to the approved system information system in relation to each contract for differences:
   (a) whether there is a special credit clause:
   (b) whether the volume of electricity, in respect of which payments are required to be made by the floating-price payer, is flat or varies for different trading periods:
   (c) whether the contract has been traded on the EnergyHedge platform. The EnergyHedge platform is a centralised trading platform for standardised derivative contracts on electricity prices in New Zealand:
   (d) whether the contract has been prepared based on the standardised schedule, which can be adopted in conjunction with the International Swaps and Derivatives Association Master Agreement, as may be available on EnergyHedge.

(4) In addition to the information that must be submitted in accordance with subclauses (2) and (3), the following information must be submitted to the approved system information system in relation to each contract for differences that has a term of less than 10 years and each fixed-price physical supply contract that has a term of less than 10 years:
   (a) the contract price calculated in accordance with clause 13.220:
   (b) the grid zone area in which the contract price is determined or applies.

(5) The information specified in this clause must be submitted in the form specified by the Authority and in accordance with clause 13.225(1).

(6) If a seller and a buyer enter into a contract for differences or fixed-price physical supply contract that includes more than 1 contract price schedule, the party required to submit information in accordance with clause 13.218 must do so in accordance with 1 of the following methods:
(a) if the contract includes contract price schedules relating to more than 1 grid zone area, by combining the information relating to all contract price schedules within each grid zone area and submitting that combined information to the approved system information system as if there were 1 contract for each grid zone area:

(b) if the contract includes contract price schedules relating to more than 1 node, by combining the information relating to all contract price schedules at each node and submitting the combined information to the approved system information system as if there were 1 contract for each node:

(c) if the party does not wish to combine the information in accordance with paragraphs (a) and (b), by submitting the information for each contract price schedule to the approved system information system individually, as though each contract price schedule was a separate contract.

(7) To avoid doubt, if a contract for differences or fixed-priced physical supply contract includes an adjustment clause,—

(a) the information that must be disclosed in accordance with this clause, in relation to the contract, must only be disclosed once; and

(b) the contract price to be disclosed in accordance with subclause (4) is that which first applies under the contract.

13.220 Calculation of contract price

... (2) The Authority may issue guidelines on the approved system to provide assistance to sellers and buyers in determining what information must be submitted to the approved system information system, which may include clarification as to how to apply the formula in subclause (1) in the circumstances covered by clause 13.219(6).

13.221 Node and grid zone area information

(1) The WITS manager Authority must publish annually, on the information system, —

(a) a list of all nodes at which the pricing manager makes publishes final prices available on WITS; and

(b) a corresponding location factor for each such node; and

(c) a corresponding grid zone area for each such node; and

(d) a list of nominated zone nodes, being 1 node at which the pricing manager makes publishes final prices available on WITS, within each grid zone area.

(2) For the purposes of subclause (1)(b), the location factor for each such node must be calculated as follows:

\[ LF = \frac{A}{B} \]

where

A is the average final price made available on WITS published at that node over the 12 month period preceding the month before the date on which the location factors are published

B is the average final price made available on WITS published at the relevant nominated zone node, as published in accordance with subclause (1)(d), for the 12
month period preceding the month before the date on which the **location factors** are published.

LF is the **location factor** to be **published** in accordance with subclause (1)(b).

**13.222 Other information that must be submitted**

(1) The following information must be submitted to the **approved system information system** in relation to every **risk management contract**:

(a) each **party**’s legal name;

(b) each **party**’s email address for notice.

(2) The information must be submitted in accordance with clause 13.225(1).

**13.223 Modified or amended information**

(1) If a modification or amendment is made to a **risk management contract**, after the information referred to in clauses 13.219 or 13.222 has been submitted to the **approved system information system**, and the effect of the modification or amendment is that the information submitted to the **approved system information system** is no longer correct or complete, the modified or amended information must be submitted to the **approved system information system**.

(2) The information submitted under subclause (1) must—

(a) identify in each case the information that has been modified or amended; and

(b) be in the form specified by the **Authority**; and

(c) be submitted in accordance with clause 13.225(2).

**13.224 Correction of information**

Except when clause 13.223 applies, if a **party** to a **risk management contract** discovers that information previously submitted to the **approved system information system** about that **risk management contract** is incorrect or incomplete, that **party** must—

(a) seek to agree with the **other party** to the **risk management contract** that the information is incorrect or incomplete and how it should be corrected; and

(b) when both **parties** have agreed that the incorrect or incomplete information should be corrected, submit the corrected information to the **approved system information system** in accordance with clause 13.225(3).

**13.225 Timeframes for submitting information**

(1) The information specified in clauses 13.219 and 13.222 must be submitted to the **approved system information system**—

(a) in respect of a **contract for differences** or an **options contract**, no later than 5pm, 5 **business days** after the **trade date**; and

(b) for any other type of **risk management contract**, no later than 5pm, 10 **business days** after the **trade date**.

(2) The modified or amended information submitted under clause 13.223(1) must be submitted to the **approved system information system** no later than 5pm, 5 **business days** after the amendment or modification to the **risk management contract** is made.

(3) The **participant** that who discovered, in accordance with clause 13.224, that any information it submitted to the **approved system** was incorrect or incomplete, must submit...
the corrected information to the approved system information system no later than 5pm, 2 business days after both parties to the risk management contract have agreed how the incorrect or incomplete information should be corrected.

(4) The corrected information submitted in accordance with clause 13.227(8) must be submitted to the approved system information system no later than 5pm, 2 business days after the parties to the risk management contract have agreed, in accordance with clause 13.227(5)(b), that the information made publicly available under clause 13.226(1) is not correct, and corrected the information accordingly.

13.226 WITS manager must Information system will make information publicly available to the public

(1) The WITS manager must make the information submitted under clauses 13.219, 13.223(1), and 13.224 publicly available on the approved system as soon as practicable.

(2) At the same time that it makes the submitted information publicly available in accordance with subclause (1), for all information other than that submitted under clause 13.224, the WITS manager information system must—
   (a) indicate on the approved system that the information is unverified; and
   (b) if the contract is a contract for differences or an options contract, give send a written notice to the other party to the contract—
      (i) (if the other party is a participant) requiring the other party to submit a verification notice to the approved system information system within 2 business days of receiving the notice confirming whether or not the information is correct; or
      (ii) (if the other party is not a participant) giving the other party the option to submit a verification notice to the approved system information system within 2 business days of receiving the notice confirming whether or not the information is correct; or
   (c) if the contract is a fixed-price physical supply contract, give a written notice to the other party giving the other party the option to submit a verification notice to the approved system information system within 2 business days confirming whether or not the information is correct.

(3) A participant who receives a verification notice under subclause (2)(b)(i) must comply with the written notice.

13.227 Verification of information

(1) If the other party to a risk management contract submits a verification notice to the information system within 2 business days of receiving notice under clause 13.226(2) confirming that the information made publicly available under clause 13.226(1) is correct, the WITS manager information system must indicate that the information made publicly available under clause 13.226(1) is verified.

(2) The WITS manager information system must indicate on the approved system that the information made publicly available under clause 13.226(1) is not disputed, if—
   (a) the other party to a contract for differences or an options contract is not a participant and does not submit a verification notice to the approved system
information system within 2 business days of receiving notice under clause 13.226(2)(b)(ii); or
(b) the other party to a fixed-price physical supply contract does not submit a verification notice to the approved system information system within 2 business days of receiving notice under clause 13.226(2)(c).

(3) If the other party to a risk management contract submits a verification notice to the WITS manager information system within 2 business days of receiving notice under clause 13.226(2) advising that the information made publicly available under clause 13.226(1) is not correct, the approved system information system must indicate that the information is disputed.

(4) If the other party to a contract for differences or an options contract is a participant but does not submit a verification notice within 2 business days of receiving notice in accordance with clause 13.226(2)(b)(i), the WITS manager information system must—
(a) indicate on the approved system that the information made publicly available in accordance with clause 13.226(1) is pending verification; and
(b) give send the other party a written reminder notice requiring the other party to submit a verification notice as soon as possible.

(5) If the information made publicly available under clause 13.226(1) is disputed, the WITS manager information system must—
(a) indicate on the approved system that the information is disputed; and
(b) give send the parties to the relevant risk management contract a written notice requiring the parties to use all reasonable endeavours to agree on whether the information submitted in accordance with clause 13.225(1) is correct or not within 10 business days of receiving the notice.

(6) The parties must comply with any notice given issued under subclauses (4)(b) or (5)(b).

(7) If the parties to the risk management contract agree in accordance with subclause (5)(b) that the information made publicly available in accordance with clause 13.226(1) is correct, the other party must submit a verification notice to the approved system information system within 1 business day confirming that the information is correct.

(8) If the parties to a risk management contract agree in accordance with subclause (5)(b) that the information made publicly available in accordance with clause 13.226(1) is not correct, the party that submitted that information to the approved system information system must correct that information in accordance with clause 13.225(4).

(9) If, within 10 business days of receiving the notice sent in accordance with subclause (5)(b), the parties to the relevant risk management contract are not able to agree whether or not the information made publicly available in accordance with clause 13.226(1) is correct, despite using all reasonable endeavours, the WITS manager information system must indicate on the approved system that the information is subject to a long term dispute.

13.228 Confirmation of information submitted to the approved system information system

(1) The WITS manager information system must, using the approved system, confirm receipt of any information received by it under clauses 13.21, or 13.222 to 13.224.

(2) Each confirmation under subclause (1) must contain a copy of the information received through by the approved system information system, together with the date and time of receipt.
13.229 Submitting party to check if no confirmation received

(1) If a **party** that submitted information to the **approved system information system** has not received confirmation from the **WITS manager** in accordance with clause 13.288(1) that its information has been received by the **approved system information system** within 6 hours of submitting the information to the information system, that **party** must, within 1 **business day** of the expiry of that 6 hour period, contact the **market administrator** to check whether the information has been received by the **approved system information system**.

(2) If the **approved system information system** has not received the information, the **party** must resubmit the information.

(3) This process must be repeated until the **WITS manager information system** has confirmed receipt of the information from the **party** in accordance with clause 13.228.

13.230 Certification of information

(1) Each **participant** who has submitted information to the **information system** in accordance with clause 13.225 in a particular **year** must provide, within 3 months of the end of the **year**, a certificate to the **Authority** verifying that the information submitted was correct.

(2) The certificate must be—
   (a) in the form of a declaration; and
   (b) in the form specified by the **Authority**; and
   (c) signed and dated by either—
      (i) 2 directors of the **participant**; or
      (ii) the chief financial officer, or person holding an equivalent position, of the **participant**; or
      (iii) the chief executive officer, or person holding an equivalent position, of the **participant**.

13.231 Audit of information

(1) The **Authority** may, in its discretion, carry out an **audit** as to whether a **participant** has complied with this subpart.

(2) If the **Authority** decides under subclause (1) that a **participant** should be subject to an **audit**, the **Authority** must first give written notice to require the **participant** requiring the **participant** to nominate an appropriate **auditor**. The **participant** must provide that nomination in writing to the **Authority** within a reasonable timeframe. The **Authority** must appoint the **auditor** nominated by the **participant**. If the **participant** fails to nominate an appropriate **auditor** within a reasonable timeframe, the **Authority** may appoint an **auditor** of its own choice.

(3) A **participant** subject to an **audit** under this clause must, on request from the **auditor**, provide the **auditor** with a copy of every **risk management contract** that it has entered into in the previous 12 months or within such other period specified by the **auditor**. The **participant** must provide this **audit** information no later than 20 **business days** after receiving a request from the **auditor** for the information.

(4) The **participant** must ensure that the **auditor** provides the **Authority** with an **audit** report on the **participant’s** compliance with this subpart that has been prepared in accordance with subclauses (4A) and (5).
(4A) The audit report must include any comments from the participant on any non-compliance found by the auditor if the participant provided comments to the auditor within a time specified by the auditor.

(5) The audit report must not contain any risk management contract that the participant has provided to the auditor in accordance with subclause (3), unless the Authority has specifically requested that the auditor do so.

13.233 WITS manager Information system and Authority must not publish certain information and may use information only under this subpart

(1) The Authority must keep, and ensure that the WITS manager information system and each auditor appointed under clause 13.231(2) keep, information submitted to the approved system information system under clauses 13.219, or 13.222 to 13.224 and copies of any risk management contract provided to the auditor under clause 13.231 confidential, unless—
   (a) the information is provided by the Authority to subcontractors or service providers that the Authority appoints to provide services for the purposes of this subpart, and those subcontractors or service providers have agreed to keep that information confidential, on the same terms as apply to the Authority under this clause; or
   (b) the information is required to be disclosed by law; or
   (c) the party or parties to whom the information relates have provided written consent to the disclosure; or
   (d) any of the information in a risk management contract is made publicly available in accordance with clause 13.226(1).

(2) The Authority may use the information submitted to the information system under clause 13.222 and copies of a risk management contract provided to the Authority by an auditor appointed under clause 13.231(2) only for purposes related to this subpart and the enforcement of this subpart.

13.236 Availability of information

The information that is submitted under clauses 13.219, 13.223, or 13.224 may only be removed from the approved system information system after 12 months following the termination of the risk management contract.

13.236D Authority must publishbase case, stress test, and method for calculating target cover ratio

(1) The Authority must publish a notice setting out the following:
   (a) a base case:
   (b) 1 or more stress tests:
   (c) 1 or more methods for calculating a disclosing participant's target cover ratio.

(2) If the Authority has not published a notice under subclause (1) at least 30 working days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, a disclosing participant is not required to prepare or submit a spot price risk disclosure statement for the next quarter.

(3) If the Authority publishes an amendment to a notice, or revokes and replaces a notice, within 30 working days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, disclosing participants must
prepare **spot price risk disclosure statements** for the immediately following quarter in accordance with the notice as in force immediately before the amendment or replacement was made and not in accordance with the notice as amended or replaced.

13.236E Content of spot price risk disclosure statements
(1) A **spot price risk disclosure statement** submitted under this subpart must include the following:
   (a) the disclosing participant's annual net cash flow from operating activities as set out in the disclosing participant's most recent set of audited annual financial statements:
   (b) the disclosing participant's level of shareholders' equity as set out in the disclosing participant's most recent set of audited annual financial statements:
   (c) the disclosing participant's estimate of the value of electricity that it expects to sell to the clearing manager during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of the value of that electricity under the base case for that period:
   (d) the disclosing participant's estimate of the value of electricity that it expects to purchase from the clearing manager during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of the value of that electricity under the base case for that period:
   (e) the disclosing participant's estimate of the projected net cash flows from operating activities of the disclosing participant during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of those cash flows under the base case for that period:
   (f) a statement as to whether the disclosing participant has an explicit risk management policy in respect of its exposure to the wholesale market:
   (g) if the disclosing participant has an explicit risk management policy, the disclosing participant's target cover ratio, for each stress test, calculated in accordance with the relevant method published by the Authority under clause 13.236D for the quarter to which the statement relates.

13.238 Preparation and publication of FTR allocation plan
(1) The **FTR manager** must prepare and publish an FTR allocation plan that complies with Schedule 13.5.
(2) The FTR manager must keep make the FTR allocation plan published available to the public at no cost on the FTR manager's website at all reasonable times.
(3) Subject to subclause (4), if Schedule 13.5 is amended, the FTR manager must, no later than 3 months after the date on which the amendment comes into force, submit to the Authority for approval under clause 13.241(4), a variation to the FTR allocation plan to make the FTR allocation plan consistent with Schedule 13.5.
(4) The FTR manager is not required to comply with subclause (3) if no amend

13.247 FTR manager must operate FTR register
(1) The FTR manager must create and operate an FTR register that records—
   (a) the holdings of FTRs; and
   (b) the FTR acquisition cost for each FTR; and
(c) assignments of FTRs including any price disclosed under clause 13.249; and
(d) the amount of electricity (in MW) to which each FTR relates; and
(e) the reconfiguration of each offered FTR.

(2) The **FTR register** must contain an account for each holder of an **FTR**.

(3) The **FTR manager** must assign a registered number to each **FTR** recorded in the **FTR register**.

(4) The **FTR manager** must maintain and publish and keep published an up to date copy of the **FTR register** make at no cost on the **FTR manager**’s website at all reasonable times.

13.248 Assignment of FTRs

(1) If a person ("assignor") wishes to assign an **FTR** or part of an **FTR** to another person ("assignee"), the assignor and assignee must complete and sign Form 1 in Schedule 13.6 and provide it to the **FTR manager**.

(2) The completed form may be provided to the **FTR manager** under subclause (1) transmitted in electronic form through the **information system** if—
   (a) both the assignor and assignee consent to completing and signing the form electronically; and
   (b) the electronic form contains all of the information required by Form 1 in Schedule 13.6; and
   (c) the notification of assignment to the **FTR manager** is in a format specified by the **FTR manager**.

(3) The **FTR manager** must not register an assignment in the **FTR register** unless the **FTR manager** is satisfied that the assignee complies with prudential requirements in Part 14A.

(4) The **FTR manager** must maintain and publish and keep published an up to date copy of the **FTR register** make at no cost on the **FTR manager**’s website at all reasonable times.

13.251 Information to be provided to FTR manager

(1) Each **grid owner** must provide a written forecast of the configuration and capacity of the **grid owner's grid** for the **FTR period** (as advised to each **grid owner** by the **FTR manager**) to the **FTR manager** for use in determining the **FTRs** to be offered in each **FTR auction**.

(2) The information that each **grid owner** must provide must include relevant planned outages.

(3) Except as otherwise agreed with the **FTR manager**, each **grid owner** must provide the information to the **FTR manager** no later than 1 month before the date (as advised to each **grid owner** by the **FTR manager**) on which an **FTR auction** is to be held.
(4) The clearing manager must advise the FTR manager in writing—
(a) whether a person who has applied to participate in an FTR auction complies with prudential requirements in Part 14A; and
(b) the amount of security that a person who has applied to participate in an FTR auction has provided that exceeds that person's other obligations under Parts 14 and 14A.

(5) Except as otherwise agreed with the FTR manager, the clearing manager must provide the information to the FTR manager no later than 2 business days before the date (as advised to the clearing manager by the FTR manager) on which an FTR auction is to be held.

(6) If the information referred to in subclause (4) changes, the clearing manager must, if requested by the person who has applied to participate in an FTR auction, provide the updated information in writing to the FTR manager.

(7) The clearing manager must inform the FTR manager written notice, as soon as practicable after receiving a request from the FTR manager, whether an assignee of an FTR meets the prudential security requirements in Part 14A.

13.252 Information to be provided to clearing manager

(1) The FTR manager must provide the following information to the clearing manager in writing in relation to each successful bidder in an FTR auction:
(a) the details of each FTR allocated under an FTR auction, including—
(i) the period to which the FTR applies; and
(ii) whether the FTR is an option FTR or an obligation FTR; and
(iii) the formula under which the FTR hedge value is to be calculated for the settlement of the FTR:
(b) the FTR acquisition cost in respect of each FTR.

(2) The FTR manager must provide the information specified in subclause (1) to the clearing manager as soon as practicable and no later than 1 week after each FTR auction.

13.253 Transmission of information to FTR manager and clearing manager

The information required to be provided to the FTR manager and the clearing manager under clauses 13.251 and 13.252 must be transmitted through the information system, except as otherwise agreed by the parties providing and receiving the information.

13.254 Publication of results of FTR auctions

The FTR manager must, as soon as practicable after each FTR auction, publish and keep published make the results of each FTR auction available to the public at no cost on the FTR manager's website in accordance with the FTR allocation plan.

Schedule 13.4

3 Authority must publishpublicise each application for approval
On receipt of an application, the Authority must—
(a) publishpublicise the application; and
(b) provide a copy of the application to the system operator.
4 Factors that Authority must consider
Before the Authority approves an application, it must take into account—
(a) the system operator’s views as to the effect an approval would have on the system operator’s ability to meet the PPOs; and
(b) the cumulative effects, if the approval were granted, of all approvals granted under this Schedule on the system operator’s ability to meet the PPOs; and
(c) any views that may be made known to the Authority within the time specified by the Authority when it published the application in accordance with clause 3(a); and

8 Authority's decision
(1) The Authority must, no later than 6 months after receiving an application,—
(a) approve each generating unit that is the subject of the application as either—
   (i) a type A industrial co-generating station; or
   (ii) a type B industrial co-generating station; or
(b) decline to approve the application.
(2) The Authority must consult with an applicant before making a decision if the Authority—
(a) proposes to approve an application for a type of industrial co-generating station other than the applicant's preference specified under clause 2(1)(d); or
(b) proposes to decline the application.
(3) The Authority must, as soon as practicable after making a decision,—
(a) advise the applicant, the system operator, the grid owner, and the clearing manager in writing; and
(b) publish its decision, including—
   (i) the reasons for the decision; and
   (ii) in the case of an application that has been approved, any conditions that have been imposed.

10 Effect of approval
Approval of 1 or more generating units as a type A industrial co-generating station or a type B industrial co-generating station takes effect from the date specified in the approval, which may be no earlier than 10 business days after the date of the notice of decision published by the Authority under clause 8(3).

Part 14
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 WITS, the electronic facility contained in the information system for the purpose and publish the information; and
(b) if the participant requests, post or hand deliver the information to the participant.
(2) Proof of dispatch of submitting the information to by WITS is the electronic facility
contained in the information system for the purpose 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 Participant to confirm receipt

(1) Each participant that receives information from the clearing manager under this subpart must immediately confirm, through WITS the electronic facility contained in the information system for the purpose, 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. The clearing manager has not received a confirmation that the information has been received by a participant by 1200 hours on the business day after the day of dispatch of the information, the clearing manager must telephone the participant to check if the information has been received.

(3) If the participant the information has not been received the information—by the participant, the clearing manager must resubmit resend 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.

14.53 Authority may publish publicise information about event of default

(1) The Authority may publish publicise information about an event of default if the Authority considers it is appropriate.

(2) If an event of default results in a reduction in payments under subpart 8, the Authority must publish publicise information about the following:
   (a) the nature of the event of default;
   (b) the extent of the event of default;
   (c) the identity of the defaulting participant.

14.71 Clearing manager to publish block dispatch settlement differences

(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 make available on WITS publish the following information for participants on WITS the information system:
   (a) the maximum block dispatch settlement difference for each block dispatch group for the previous billing period as determined by the following formula:

   \[
   \text{Settlement Difference} = \max \left\{ \sum_{g_{ip} = 1}^{g_p} P_{g_{ip}} \left\{ \frac{\text{Gen}_{g_{ip}}}{\text{Set}_{g_{ip}}} - \frac{\sum \text{Gen}_{g_{ip}, i}}{\sum \text{Set}_{g_{ip}}} \right\} \right\}
   \]

   (b) the total block dispatch settlement differences for each block dispatch group for the
previous **billing period** as determined by the following formula:

where

\[ P_{gip} \] is the final price at the relevant **grid injection point** for the **generating plant** or **generating unit** that forms part of the **block dispatch group** for the relevant **trading period** of the **billing period**

\[ \text{Gen}_{gip} \] is the final quantity of **electricity** sold by that **generator** to the **clearing manager** at the relevant **grid injection point** for the **generating plant** or **generating unit** that forms part of the **block dispatch group**, obtained from the **reconciliation information** for the relevant **trading period** of the **billing period**

\[ \text{Set}_{gip} \] is the generation quantity at the relevant **grid injection point** for the **generating plant** or **generating unit** that forms part of the **block dispatch group** for the relevant **trading period** of the **billing period**

\[ P_{gip,i} \] is the final price at the relevant **grid injection point** for the **generating plant** or **generating unit** that forms part of the **block dispatch group** for the relevant **trading period** of the **billing period**

\[ \text{Gen}_{gip,i} \] is the final quantity of **electricity** sold by that **generator** to the **clearing manager** at the relevant **grid injection point** for the **generating plant** and **generating units** that form part of the **block dispatch group**, obtained from the **reconciliation information** for the relevant **trading period** of the **billing period**

\[ \text{Set}_{gip,i} \] is the generation quantity at the relevant **grid injection point** for the **generating plant** and **generating units** that form part of the **block dispatch group** for the relevant **trading period** of the **billing period**.

### 14.72 Clearing manager to make block dispatch settlement differences available on WITS later if WITS information system is unavailable

1. **If WITS** the information system is unavailable to **make publish** the information set out in clause 14.71 available in accordance with that clause, the **clearing manager** is not obliged to follow any backup procedures in respect of making publishing the information available.

2. **The clearing manager** must make available on **WITS publish** the information as soon as reasonably possible after **WITS the information system** 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 WITS the information system is deemed to be delivered on the date it was transmitted.

(3) Any notice or demand delivered, or deemed to be delivered, on a day that is not a business day, or after 1600 hours on a business day, is deemed to have been delivered on the next business day.

Part 14A

14A.21 Clearing manager to provide information about required security
...
(2) The clearing manager must provide the information to the participant through the WITS and publish the information system.

14A.24 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 WITS the information system is deemed to be delivered on the date it was transmitted.
(3) Any notice or demand delivered, or deemed to be delivered, on a day that is not a business day, or after 1600 hours on a business day, is deemed to have been delivered on the next business day.
CRP 2016-15  Simplifying Code terms about ‘notifying’ information

Part 1

**declaration date** means the date, nominated by the **profile applicant**, on which the **market administrator** must, for a particular **profile**, give written notice to notify every **registered participant** of the information set out in clause 13 of Schedule 15.5 for that **profile**

**notify** means to notify the persons referred to in the relevant clause by way of letter, e-mail or facsimile, to a contact person and address provided by that person, that the information referred to in that clause has been **published**

**notified planned outages** means planned outages of **assets** forming part of or **connected** to the **grid** or **local network** that have been planned by the **asset owners** concerned and have been notified in relation to which written notice has been given to the **system operator** in accordance with **Technical Code D** of Schedule 8.3

Part 2

2.2 Information held by Authority

If the **Authority** receives a request for the supply of **Code information** that the **Authority** holds, the **Authority** must—

(a) consider and process the request in accordance with the **Official Information Act 1982**; and

(b) give written notice to notify the **participant** with which the information originated of the request for the supply of that information, before supplying it.

2.4 Authority must contact participant believed to hold requested information

The **Authority** must, as soon as practicable after receiving a request for the supply of **Code information** that it does not hold, send a written notice to the **participant** who the **Authority** believes holds the relevant **Code information**—

(a) giving notifying the **participant** written notice of the request made to the **Authority**, and the name and address of the requesting **participant**; and

(b) requesting the **participant** to either—

(i) supply the information, together with a note of the **participant’s** charges (if any) in relation to the supply of information; or

2.14 Process if participant refuses to supply information

(1) If the **participant** refuses to supply all or any of the **Code information** requested, the **participant** must, as soon as practicable, give written notice to notify the **Authority** and the requesting **participant** of both the refusal and of the reasons for the refusal.

(2) The **Authority** must, as soon as practicable after receiving the notice that notification, advise the requesting **participant** of its rights to appeal under clause 2.15.
Part 6

Schedule 6.2 – Regulated Terms for distributed generation

15 Permanent disconnections

(1) Despite clause 10, the distributor may permanently disconnect distributed generation in the following circumstances:

(a) on receipt of a request from a distributed generator;

(b) without notice, if a distributed generator has been temporarily disconnected under clause 11(g) and—
   (i) the distributed generator fails to remedy the non-compliance within a reasonable period of time; and
   (ii) there is an ongoing risk to persons or property:

(c) without notice, if the trader that is recorded in the registry as being responsible for the ICP to which the distributed generation is connected to the distribution network has de-energised the ICP and advised the registry that the ICP has a status of "inactive" with the reason of "de-energised – ready for decommissioning":

(d) on at least 10 business days' notice of intention to disconnect, if—
   (i) the distributed generator has not injected electricity into the distribution network at any time in the preceding 12 months; and
   (ii) the distributor has not been given written notice notified by the distributed generator of reasons for the non-injection; and
   (iii) the distributor has reasonable grounds for believing that the distributed generator has ceased to operate the distributed generation.

...
application will exceed the estimate given under clause 3(c) or any revised estimate given under clause 4; or

(ii) an asset owner varies its application and the system operator, acting reasonably, considers this variation will change the cost of processing the application.

(2) The system operator is entitled not to proceed until agreement on costs is reached at any of these stages.

6 Special provisions relating to the grant of dispensations

(1) Before granting a dispensation, the system operator must issue a draft decision on the application. The draft decision must be published on the system operator register and must include—

(a) an assessment by the system operator of the technical issues; and

(b) advice from the system operator about any changes required to ancillary services procurement as a result of the proposed dispensation.

(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 clause 8.44.

(3) A participant may make a submission to the system operator on the application that resulted in the publication of the draft decision no later than 10 business days after the draft decision is recorded on the system operator register.

(4) All submissions must be considered by the system operator, and the system operator must notify give written notice to any participant who made a submission as to the system operator's decision on the application.

Schedule 8.2

1 Process for approval of alternative ancillary service arrangement

(1) An application for an alternative ancillary service arrangement must—

(a) be in writing; and

(b) specify the ancillary service for which approval for an alternative ancillary service arrangement is sought; and

(c) provide supporting information for the application, including sufficient information about the actual capability of the asset or configuration of assets; and

(d) describe any remedial action planned to return the asset or configuration of assets to a compliant state; and

(e) specify the required term of the alternative ancillary service arrangement; and

(f) indicate any information for which confidentiality is sought on the grounds that it would, if disclosed, unreasonably prejudice the commercial position of the person who supplied the information (or the person who is the subject of that information), or would disclose a trade secret, or on the ground that it is necessary to protect information which is itself subject to an obligation of confidence.

(2) No later than 5 business days after receipt of the application under subclause (1), the system operator must—

(a) record the name of the asset owner making the application, the date and the subject matter of the application in the system operator register; and

(b) notify give written notice to the Authority of the application; and
(c) provide the asset owner with an estimate of the likely time it will take to consider the application and the likely costs associated with processing the application.

(3) The system operator and the asset owner must agree on the costs involved in processing an application for authorisation of an alternative ancillary service arrangement and the method for payment to the system operator by the asset owner of those costs—
(a) before the system operator proceeds with the application; and
(b) at any time during the processing of the application, the system operator is entitled not to proceed until agreement is reached if either—
   (i) the system operator notifies the asset owner that it considers the estimate of the likely timeframe and costs involved in processing the application will exceed the estimate given under subclause (2)(c); or
   (ii) an asset owner varies its application and the system operator, acting reasonably, considers this variation will change the costs in processing the application.

7 Modifications and changes to assets

(1) Assets that have been modified, or are proposed to be modified, are deemed to be new assets for the purposes of this Code and this Technical Code and are subject to the requirements for connection to the grid and the requirements for commissioning assets. For the purposes of this Schedule, the following are considered to be modifications to assets, if the new connection or alteration may affect the capacity of the assets or may affect asset owner performance obligations or technical code requirements:
   (a) a new connection of assets to the grid or a local network:
   (b) a new connection of assets to form part of the grid:
   (c) a new connection of an embedded generator to a local network other than an excluded generator as defined in clause 8.21(1):
   (d) an alteration to assets already connected to the grid or, in the case of embedded generator, already connected to a local network.

(2) The asset owner must notify the system operator in a timely manner of any assets that have been decommissioned if the assets affect or could affect the system operator’s ability to comply with its principal performance obligations.

Schedule 8.3

9 Obligations of generators and ancillary service agents to take independent action

The following independent action is required of generators and ancillary service agents during the occurrence of extreme variations of frequency or voltage at the points of connection to which their assets are connected (such extreme levels of frequency or voltage are deemed to constitute a grid emergency and require a fast and independent response from each generator and each ancillary service agent):

…

(f) in the event of a failure at the system operator’s operational centre that disables the main dispatch or communication systems, the system operator may temporarily transfer its operational activities to an alternative operational centre, and the system operator must arrange for communication facilities to transfer to the new location and must notify written notice to participants of those arrangements.
Schedule 8.3, Technical Code B

9 Obligations of generators and ancillary service agents to take independent action

The following independent action is required of generators and ancillary service agents during the occurrence of extreme variations of frequency or voltage at the points of connection to which their assets are connected (such extreme levels of frequency or voltage are deemed to constitute a grid emergency and require a fast and independent response from each generator and each ancillary service agent):

(a) …

(f) in the event of a failure at the system operator’s operational centre that disables the main dispatch or communication systems, the system operator may temporarily transfer its operational activities to an alternative operational centre, and the system operator must arrange for communication facilities to transfer to the new location and must give written notice to notify participants of those arrangements.

Schedule 8.3, Technical Code C

8 Notification of planned outages of primary means of communication

Each asset owner must notify give written notice to the system operator of any planned outage of a primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2).

Schedule 8.3, Technical Code D

1 Purpose

The purpose of this technical code is to set out the obligations of asset owners to notify give written notice of planned outages of assets that affect common quality, and to set out the obligations of the system operator in relation to outage co-ordination and the provision of timely advice to asset owners on the security implications of notified planned outages.

2 Notification of planned outages

(1) Each asset owner must, in relation to each of its assets, notify give written notice to the system operator as soon as practicable of all planned outages of such assets if such outages may impact on the system operator’s ability to plan to comply, and to comply, with the principal performance obligations.

(2) If the asset owner is unsure whether an outage of an asset may impact on the system operator’s ability to plan to comply, and to comply, with the principal performance obligations, the asset owner must contact the system operator for advice.

(3) Each asset owner must notify give written notice to the system operator up to 12 months ahead of planned outages and update the system operator of changes to the planned outages as and when the asset owner becomes aware of them.

Part 10

Schedule 10.3

7 Notification of cancellation, expiry, or revision of scope of ATH approval

(1) The Authority must notify give written notice to all metering equipment providers if—

(a) an ATH’s approval expires and the Authority does not renew it:
(b) the Authority cancels an ATH’s approval under clause 5:
(c) an ATH’s approval is cancelled under clause 6(2) or 6(3)(a):
(d) the scope of an ATH’s approval has been revised under clause 6(3)(b).

(2) The Authority must include with the notification notice under subclause (1) the date on which the approval expired or was cancelled, or the scope of the approval was revised.

(3) A metering equipment provider given notice under subclause (1) must treat all metering installations certified by the ATH during the period during which it was not validly approved, or was performing activities outside its scope of approval, as being defective from the date notified under subclause (2) and follow the procedures set out in clauses 10.43 to 10.48.

(4) Despite subclause (3), the Authority may notify a metering equipment provider written notice that the metering equipment provider must treat a metering installation certified by the ATH as being defective and follow the procedures set out in clauses 10.43 to 10.48.

Part 11

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 notify the registry, 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 notification under subclause (2) must notify the distributor if it wishes to add an ICP to or omit an ICP from the ICPs across which the unmetered load is shared.
(4) A distributor who receives notification under subclause (3) must notify the registry and each trader responsible for any of the ICPs across which the unmetered load is shared.
(5) If a distributor becomes aware of a change to the capacity of an ICP across which the unmetered load is shared or that an ICP across which the unmetered load is shared is decommissioned, it must notify written notice to all traders who receive notification under subclause (2) of the change or decommissioning as soon as practicable after the change or decommissioning.
(6) A trader who receives notification under subclause (5) must, as soon as practicable after receiving the notification, adjust the unmetered load information for each ICP for which it is responsible, so that the unmetered load is shared equally across each of those ICPs.
(7) A trader must take responsibility for shared unmetered load assigned to an ICP for which the trader becomes responsible as a result of a switch in accordance with this Part.
(8) A trader must not relinquish responsibility for shared unmetered load assigned to an ICP if there would then be no ICPs left across which the load could be shared.
(9) A trader who changes the status of an ICP across which the unmetered load is shared to inactive in accordance with clause 19 of Schedule 11.1 is not required to notify written notice to the distributor of the change under subclause (3). The amount of electricity attributable to that ICP becomes UFE.
11.32C Retailers must notify consumers of availability of information

Each retailer must notify give written notice to each consumer with whom it has a contract to supply electricity of the consumer's ability to make a request to the retailer under clause 11.32B, so that the consumer is notified at least once in each calendar year.

Schedule 11.1

8 Distributors to change ICP information provided to registry

(1) If information about an ICP provided to the registry in accordance with clause 7 changes, the distributor in whose network the ICP is located must notify give written notice to the registry of the change.

(2) The distributor must give the notification notice—

(a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the commissioning or decommissioning of an NSP), no later than 8 business days after the change takes effect; and

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

(3) A distributor is not required to notify give written notice of a change of information provided in accordance with clause 7(1)(b) if the change is for less than 14 days.

(4) If a change of information provided in accordance with clause 7(1)(b) is for more than 14 days, subclause (2) applies as if the change had taken effect on the 15th day after the change takes effect.

24 Balancing area information

(1) A distributor must notify give written notice to the reconciliation manager of the establishment of a balancing area associated with an NSP supplying the distributor's network, in accordance with clause 26.

(2) A distributor must notify give written notice to the reconciliation manager of any change to the information provided under subclause (1).

(3) The notification notice must—

(a) specify the date and trading period from which the change takes effect; and

(b) be given no later than 3 business days after the change takes effect.

(4) The reconciliation manager must notify give written notice to the registry of changes to balancing areas within 1 business day after receiving the notification notice.

(5) The registry must publish an updated schedule of the mapping between NSPs and balancing areas within 1 business day after receiving the notification notice.

(6) The schedule must specify the date and trading period from which the change took effect.

25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network

(1) If an NSP is to be created or decommissioned,—

(a) the participant specified in subclause (3) in relation to the NSP must notify give written notice to the reconciliation manager of the creation or decommissioning; and

(b) the reconciliation manager must notify give written notice to the market administrator and affected reconciliation participants of the creation or decommissioning no later than 1 business day after receiving the notification in paragraph (a).
(2) If a distributor wishes to change the record in the registry of an ICP that is not recorded as being usually connected to an NSP in the distributor's network, so that the ICP is recorded as being usually connected to an NSP in the distributor's network (a "transfer"), the distributor must notify the reconciliation manager, the market administrator, and each affected reconciliation participant of the transfer.

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

(a) the grid owner, if—
   (i) the NSP is a point of connection between the grid and a local network; or
   (ii) if the NSP is a point of connection between a generator and the grid; or
(b) the distributor for the local network who initiated the creation or decommissioning, if the NSP is an interconnection point between 2 local networks; or
(c) the embedded network owner who initiated the creation or decommissioning, if the NSP is an interconnection point between 2 embedded networks; or
(d) the distributor for the embedded network, if the NSP is a point of connection between an embedded network and another network.

(4) A distributor who is required to notify the reconciliation manager of a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

26 Information to be provided if NSPs are created or ICPs are transferred from 1 distributor's network to another distributor's network

(1) If a participant gives a notification under clause 25(1) or (2) of the creation of an NSP or the transfer of an ICP from 1 distributor's network to another distributor's network, the participant must request that the reconciliation manager create a unique NSP identifier for the NSP.

(2) The participant must make the request—

(a) in the case of a notification given under clause 25(3)(b) or (c), at least 10 business days before the NSP is electrically connected; and
(b) in every other case, at least 1 calendar month before the NSP is electrically connected or the ICP is transferred.

(3) If a participant gives a notification under clause 25(1) of the creation of an NSP, the distributor on whose network the NSP is located must give the reconciliation manager the following information:

(a) if the NSP is to be located in a new balancing area to be created—
   (i) all relevant details necessary for the balancing area to be created; and
   (ii) notification that the NSP to be created is to be assigned to the new balancing area; and
(b) in every other case, notification of the balancing area in which the NSP is located.

(4) If a participant gives a notification under clause 25(1) or (2) of a creation or transfer that relates to an NSP between a network and an embedded network, the distributor who owns the embedded network must notify the reconciliation manager of the following:

(a) the network on which the NSP will be located after the creation or transfer:
(b) the ICP identifier for the ICP that connects the network and the embedded network:
(c) the date on which the creation or transfer will take effect.
(5) The **distributor** must give the notification at least 1 calendar month before the creation or transfer.

27 **Information to be provided if ICPs become NSPs**

(1) If a transfer notified under clause 25 results in an ICP becoming an NSP at which an embedded network connects to a network, or in an ICP becoming an NSP that is an interconnection point, the **distributor** who owns the network on which the NSP will be located after the change must give written notice to any **trader** trading at the ICP of the transfer.

(2) The **distributor** must give the notice at least 1 calendar month before the transfer.

**Schedule 11.3**

12 **Gaining trader may change switch event meter reading**

(1) The gaining **trader** may use the switch event meter reading supplied by the losing **trader** or may, at its own cost, obtain its own switch event meter reading.

(2) If the gaining **trader** elects to use the new switch event meter reading, the gaining **trader** must give written notice to notify the losing **trader** of the new switch event meter reading and the event date to which it refers as follows:

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

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

(2A) Despite subclauses (1) and (2), subclause (2B) applies if—

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

(b) the gaining **trader** will trade electricity at the ICP through a metering installation with a submission type of half hour in the registry, as a result of the gaining **trader**’s arrangement with the customer or embedded generator; and

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

(2B) No later than 5 business days after receiving final information from the registry under clause 22(d),—

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

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

(3) If the gaining **trader** disputes a switch event meter reading under subclause (2)(b), the gaining **trader** must, no later than 4 months after the actual event date, provide to the losing **trader** a changed validated meter reading or a permanent estimate supported by 2 validated meter readings, and the losing **trader** must either,—

(a) no later than 5 business days after receiving the switch event meter reading from the gaining **trader**, the losing **trader**, if it does not accept the switch event meter reading
reading, must give written notice to notify the gaining trader (giving all relevant details), and the losing trader and the gaining trader must use reasonable endeavours to resolve the dispute in accordance with the disputes procedure contained in clause 15.29 (with all necessary amendments); or

(b) if the losing trader notifies its acceptance of the switch event meter reading received from the gaining trader, or does not provide any response, the losing trader must use the switch event meter reading supplied by the gaining trader.

22 Registry notifications
The registry must provide notification to participants required by this Schedule as follows:

(a) on receipt of information about a switch request in accordance with clauses 2, 9 and 14, the registry must give written notice to notify the losing trader of the information received;

(b) on receipt of information about a withdrawal request in accordance with clauses 18(c) and (d), the registry must give written notice to notify the other relevant trader of the information received;

(c) on receipt of information about a switch acknowledgement in accordance with clauses 3(a) and 15, the registry must give written notice to notify the gaining trader of the information received;

(d) on receipt of information about a switch completion in accordance with clauses 3(a)(ii), 5, 10 and 16, the registry must give written notice to notify the gaining trader, the losing trader, the metering equipment provider, and the relevant distributor of the information received.

4A Trader to provide information about NSPs and ICPs at which it cannot trade
(1) If the Authority gives a notice to a trader under clause 4, the Authority must give written notice to notify each trader (except the defaulting trader) that it must provide the information specified in subclause (2) to the registry manager by no later than 1600 on the business day following the day on which the notice under this subclause was given.

Part 12

12.61 Authority must publish draft grid reliability standards
(1) This clause applies if the Authority undertakes a review of the grid reliability standards under clauses 12.59 or 12.60.

(2) The Authority must publish draft grid reliability standards.

(3) At the time the Authority publishes the draft grid reliability standards the Authority must publish notify registered participants of the date by which submissions on the draft grid reliability standards are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the draft grid reliability standards.

(4) Each submission on the draft grid reliability standards must be made in writing to the Authority and be received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.
12.68 Authority must publish draft core grid determination
(1) This clause applies if the Authority undertakes a review of the core grid determination in accordance with clauses 12.66 or 12.67.
(2) The Authority must publish a draft core grid determination.
(3) When the Authority publishes the draft core grid determination the Authority must publish notify registered participants of the date by which submissions on the draft core grid determination are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the draft core grid determination.
(4) Each submission on the draft core grid determination must be made in writing to the Authority and be received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

12.82 Authority must consult on issues paper
(1) When the Authority publishes the issues paper, the Authority must publish notify registered participants of the date by which submissions are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the issues paper.
(2) Each submission on the issues paper must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear one or more oral submissions.
(3) Within 20 business days of the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on the issues paper.

12.92 Authority must publish proposed transmission pricing methodology
(1) The Authority must publish the proposed transmission pricing methodology as soon as practicable.
(2) At the time the Authority publishes the proposed transmission pricing methodology the Authority must publish notify registered participants of the date by which submissions are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the proposed transmission pricing methodology.
(3) Each submission on the proposed transmission pricing methodology must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

12.128 Transpower and designated transmission customers may agree on other requirements
(1) Transpower and each designated transmission customer must comply with this Part, unless agreed otherwise by Transpower and the designated transmission customer in respect of specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer in accordance with subclause (2).
(2) An agreement between Transpower and a designated transmission customer under this clause may not exclude the application of clause 12.118(1)(h) and must be conditional in
all respects on—

(a) obtaining agreement from all other potentially affected designated transmission customers that this Part does not apply to the specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer; and

(b) Transpower and the designated transmission customer certifying to the Authority that they have consulted with all potentially affected end use customers on this Part not applying to the specified interconnection branches, circuit branches, the HVDC link, shunt assets or interconnection assets or the designated transmission customer, and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must give written notice to notify the Authority as soon as practicable in the event that Transpower enters into an agreement with a designated transmission customer under this clause.

12.151 Compliance with Outage Protocol

(1) Transpower and each designated transmission customer must comply with the Outage Protocol, unless agreed otherwise by Transpower and a designated transmission customer in respect of specified assets or the designated transmission customer in accordance with subclause (2).

(2) An agreement between Transpower and a designated transmission customer to which the Outage Protocol does not apply in respect of specified assets may not exclude the application of clause 12.118(1)(h) and must be conditional in all respects on—

(a) obtaining agreement from all other potentially affected designated transmission customers that the Outage Protocol does not apply in respect of the specified assets or the designated transmission customer; and

(b) Transpower and the designated transmission customer satisfying the Authority that they have consulted with all potentially affected end use customers on the Outage Protocol not applying in respect of the specified assets or the designated transmission customer and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must give written notice to notify the Authority as soon as practicable if Transpower enters into an agreement with a designated transmission customer in respect of specified assets in accordance with subclause (1).

Part 13

13.27B Authority to determine conforming and non-conforming GXPs if requested

(1) Subclause (4) applies if—

(a) a purchaser or the system operator makes a request under clause 13.27H; and

(b) the Authority decides there are valid grounds to consider the request.

(2) The Authority must decide whether to proceed with the request within a reasonable time after receiving the request.

(3) If the Authority decides there are no valid grounds to consider the request, the Authority must give written notice to the requester in writing of—

(a) the Authority’s decision; and
(b) the grounds for the Authority’s decision.

(4) If subclause (1) applies, the Authority must—
(a) determine whether a GXP, which is deemed to be a conforming GXP under clause 13.27F, is a conforming GXP or a non-conforming GXP:
(b) reconsider a previous determination, and as a result may decide to replace the previous determination with a new determination.

13.28 Special treatment of some grid exit points
(1) For the purpose of this subpart and subparts 2 and 4, a purchaser, generator or market operation service provider may apply to the Authority to have 2 or more grid exit points treated as 1 grid exit point for the purposes of determining the status of a GXP under clause 13.27A or clause 13.27B(4), submitting bids, scheduling, switching, dispatch, pricing, clearing and settlement where there are 2 or more local networks supplied from the grid at the same physical location.

(2) In determining an application under subclause (1), the Authority must consider the following factors:
(a) the efficiency or otherwise, of creating a separate price for grid exit points that are at the same, or at a geographically similar location:
(b) the geographical similarity of the grid exit points that are the subject of the application:
(c) the effect on a market operation service provider in terms of added processing time and complexity in treating as separate 2 or more grid exit points that are in the same or in a geographically similar location:
(d) any submissions received from participants under subclause (3):
(e) any other matter the Authority thinks fit.

(3) The Authority must give written notice to notify participants in writing of an application under subclause (1) within 2 business days of the application being received by the Authority. Each participant has 5 business days to make submissions to the Authority on the application. The Authority must not consider an application until after the period for making submissions on the application has expired.

(4) If an application under subclause (1) has been approved, the Authority must consult with each market operation service provider about the time it may take to implement changes that are required to accommodate the decision. The Authority must then give written notice to notify each participant of the date from which its decision takes effect.

13.34 Changes may be made within 2 hours before trading period
(1) A grid owner may update the information submitted under clause 13.33 later than 2 hours before the relevant trading period only if—
(a) a bona fide physical reason necessitates the change; or
(b) the system operator issues a formal notice; or
(c) an unforeseeable change occurs in the availability of a grid owner’s assets, which were the subject of a planned or unplanned outage in relation to which written notice was given by the grid owner to the system operator.

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

(3) A grid owner who submits revised information to the system operator later than 2 hours before the relevant trading period must report each revision to the Authority in writing together with an explanation of the reasons for the revision. The grid owner must report each revision to the Authority by 1700 hours on the 1st business day following the trading day on which the revision was made.

13.46 Reserve offers may be revised or cancelled

(1) An ancillary service agent (other than an ancillary service agent who is an embedded generator) may—
   (a) revise its reserve offer prices or its reserve offer quantities, as the case may be, for any trading period by submitting a new reserve offer to the system operator. A revised reserve offer may be made up to 2 hours before the beginning of the trading period in respect of which the reserve offer is made; or
   (b) cancel a reserve offer by giving written notice to the system operator. Any such cancellation may be made up to 2 hours before the beginning of the trading period in respect of which the reserve offer was made.

(2) Despite subclause (1), and subject to clauses 13.47 and 13.97 to 13.101, an ancillary service agent who revises a reserve offer associated with an embedded generating station must use reasonable endeavours to submit the revised reserve offer at least 2 hours before the beginning of the trading period in respect of which the reserve offer is made, and may—
   (a) revise any of its reserve offer quantities for any trading period by submitting a new reserve offer to the system operator. A revised reserve offer may be made up to 30 minutes before the beginning of the trading period in respect of which the reserve offer was made; or
   (b) cancel any of its reserve offers by notice in writing to the system operator. A cancellation of a reserve offer may be made up to 30 minutes before the beginning of the trading period in respect of which the reserve offer was made.

13.60 Block dispatch may occur

(1) A generator and the system operator may agree to treat a group of generating stations as a block dispatch group.

(2) If an agreement for block dispatch has been reached, the following procedures apply:
   (a) the generator must give written notice to the system operator and the clearing manager of the agreement, at least 5 business days before the agreement takes effect, specifying—
      (i) the trading day and the trading period in which the agreement will take effect; and
      (ii) the generating stations that are the subject of the agreement; and
      (iii) the terms of the agreement; and
   (b) the system operator must identify in each non-response schedule the generating stations or generating units that are part of a block dispatch group.
(3) The generator must give written notice to notify the system operator and the clearing manager of any change to an agreement for block dispatch made under this clause or clause 13.61 at least 5 business days before the change takes effect.

13.61 System operator to notify block security constraints

(1) The system operator must give written notice to notify generators of the implication of any block security constraints that apply within the block dispatch group. The notification must include—
   (a) the trading periods for which the block security constraint applies; and
   (b) how the block security constraint divides the generating stations or generating units of a block dispatch group into sub-block dispatch groups.

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—
   (a) completion of the trading periods set out in the notice; or
   (b) receipt of another notice from the system operator in accordance with subclause (1) for the same block dispatch group for the same trading period or trading periods; or
   (c) receipt of a notice from the system operator that the block security constraint no longer exists; or
   (d) receipt of an instruction from the system operator in accordance with clause 13.75(f) for the same block dispatch group for the applicable trading period, and such instruction remains valid for the trading periods specified in that instruction.

(3) [Revoked]

13.64 Station dispatch may occur

(1) A generator may elect to have its generating plant dispatched as a station dispatch group by giving the system operator at least 15 business days’ notice in writing in the form set out in Form 8 of Schedule 13.1. The system operator must use best endeavours to implement the election within 15 business days after receiving the notice.

(2) The system operator must give written notice to notify the generator and the clearing manager of the effective date of the election at least 5 business days before the date. On and from the effective date, the procedures set out in clauses 13.65 and 13.66 must be followed by the system operator and the generator.

13.65 System operator to notify station security constraints

(1) The system operator must give written notice to notify the generator of the implication of any station security constraints that apply within a station dispatch group. The notice notification must include—
   (a) the trading periods for which the station security constraint applies; and
   (b) how the station security constraint divides the generating units or generating stations of a station dispatch group into a sub-station dispatch group or limits the generation of a station dispatch group.

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—
   (a) completion of the trading periods set out in the notice; or
(b) receipt of another notice from the system operator in accordance with subclause (1) for the same station dispatch group for the same trading period or trading periods; or
(c) receipt of a notice from the system operator that the station security constraint no longer exists; or
(d) receipt of an instruction from the system operator in accordance with clause 13.75(g) for the same station dispatch group for the applicable trading period, and the instruction remains valid for the trading periods specified in the instruction.

13.66 Generator notifies change from station to unit dispatch
If a generator changes the dispatch of its generating plant from a station dispatch group basis to a generating unit basis, it must give the system operator at least 15 business days’ notice in writing. The system operator must use best endeavours to implement the change within 15 business days of receiving a notice. The system operator must give written notice to notify the generator and the clearing manager of the effective date of the change at least 5 business days before the date.

13.128 Results
By 1100 hours on the day of each auction the clearing manager must give written notice of notify—
(a) each generator that has bid at an auction of the outcome of the auction; and
(b) all generators and purchasers of the quantity and price of all successful auction bids made at the auction.

13.165 Authority notified if provisional price situation not resolved
(1) If a grid owner or the system operator receives notice of an unresolved provisional price situation in accordance with clause 13.164, the grid owner or system operator (as the case may be) must immediately give written notice to notify the Authority of—
(a) how the unresolved provisional price situation arose; and
(b) the steps taken in attempting to resolve the provisional price situation; and
(c) the reasons for the inability of the grid owner or system operator (as the case may be) to resolve the provisional price situation.
(2) As soon as it receives a notice given under subclause (1), the Authority must consider the unresolved provisional price situation and urgently address the matters raised in the notice.

13.175 Authority to accept or reject recommendations
If the Authority receives a recommendation and reasons from the pricing manager under clause 13.174, it—
(a) must decide whether to accept the pricing manager’s recommendations; and
(b) must immediately give written notice to notify the pricing manager of the Authority's decision; and
(c) may direct the pricing manager—
(i) to take any specified action to resolve the pricing error; or
(ii) to direct, on behalf of the Authority, another participant to take any specified action to resolve the pricing error.
13.176 Pricing manager to publish notice

As soon as practicable after the Authority has given written notice notified the pricing manager of its decision under clause 13.175, the pricing manager must publish a report notifying—
(a) the name of the error claimant; and
(b) the reason for the error claimant claiming that a pricing error has occurred; and
(c) the trading periods that are claimed to have been affected by the pricing error; and
(d) the Authority's decision made under clause 13.175; and
(e) the Authority's reasons for its decision under clause 13.175; and:
(f) if the Authority decided that a pricing error had occurred, any actions it has directed be taken to correct the pricing error.

13.215 Generators and purchasers have right to information concerning pricing manager’s action

(1) A generator or a purchaser may, by giving written notice in writing to the pricing manager, request further information relating to any situation set out in a pricing manager's report published under clause 13.214 that has materially affected the generator or purchaser.

(2) In such cases, the pricing manager must provide the requested information to that generator or purchaser except that such information must not include any information that is confidential in respect of any other person.

Schedule 13.3

13 Adjustments to schedules to meet dispatch objective

(1) As soon as practicable after each non-response schedule and each dispatch schedule has been completed, the system operator must give written notice to notify participants of any changes required to the non-response schedule or dispatch schedule (as the case may be) to meet the dispatch objective, including adjustments for—
(a) voltage support; and
(b) frequency keeping reserves; and
(c) over-frequency arming; and
(d) additional transmission constraints; and
(e) instantaneous reserve.

Part 14

Schedule 14.2

Consultation on proposed changes to methodology

(1) When the Authority publishes the changes that the Authority wishes the clearing manager to make to the draft methodology under clause 2(5), the Authority must publish notice to notify the clearing manager and interested parties of the date by which submissions on the changes must be received by the Authority....
Part 15

15.14 Notification of changes to the grid
(1) Each grid owner must give written notice to notify the reconciliation manager, in accordance with any procedures or other requirements reasonably specified by the reconciliation manager from time to time, of any changes that the grid owner intends to make to the grid that will affect reconciliation.
(2) The grid owner must give the notice at least 1 calendar month before the effective date of the intended change.
(3) No later than 1 business day after receipt of the notice, the reconciliation manager must give a copy of the notice to the clearing manager and the Authority.
(4) Each grid owner must give notice of an intended change to an existing point of connection to the grid or a new point of connection to the grid to be commissioned.

15.15 Notification of points of connection subject to outages or alternative supply
No later than 2 hours after publication of final prices for all trading periods in a consumption period,—
(a) the system operator must give written notice to notify the reconciliation manager of the following:
   (i) each point of connection to the grid that was disconnected in the consumption period:
   (ii) in relation to each point of connection referred to in subparagraph (i), the trading periods in the consumption period during which the point of connection to the grid was disconnected; and
(b) each grid owner must give written notice to notify the reconciliation manager of the following:
   (i) each point of connection to the grid that was supplied from an alternative point of connection in the consumption period:
   (ii) in relation to each point of connection referred to in subparagraph (i), the trading periods in the consumption period during which the point of connection to the grid was supplied from an alternative point of connection.

15.17 Submission information to be reviewed in the case of an outage constraint
In the case of an outage constraint, the reconciliation manager must—
(a) review the submission information in accordance with a notice received in accordance with clause 15.15 and satisfy itself that the submission information is consistent with the occurrence of the stated outage constraint; and
(b) reconcile the submission information for the affected NSP within the balancing area identified in accordance with clause 15.15 for the trading periods during which the outage constraint applied; and
(c) as soon as reasonably practicable, but no later than 2 business days after publication of final prices, give written notice to notify any reconciliation participants who were affected by the outage constraint affecting the NSPs, of the trading periods in the prior consumption period during which the outage constraint applied, and any changes to balancing area NSP groupings made in accordance with clause 15.16; and
(d) …

Schedule 15.1

8 Changes that affect certification

(1) If a reconciliation participant intends to make a change to any of its facilities, processes or procedures that the reconciliation participant considers is material, the reconciliation participant must, at least 5 business days before the change is to take place,—
   (a) give written notice to notify the Authority of the change; and
   (b) submit to the Authority an audit report confirming that, after the change has come into effect, the reconciliation participant will continue to meet the requirements specified in clause 5.

(2) The Authority must, by notice to the reconciliation participant, continue a 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 deemed to be revoked if—
   (a) a reconciliation participant fails to give the notice required by subclause (1); or
   (b) the Authority notifies 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.

8A Timeframe for auditing a change extended

(1) This clause applies if a reconciliation participant intends to make a change to any of its facilities, processes, or procedures that—
   (a) the reconciliation participant considers is material; and
   (b) is required to implement the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

(2) Despite clause 8(1), a reconciliation participant must, no later than 4 months after the amendment comes into force—
   (a) given written notice to notify the Authority of the change; and
   (b) submit to the Authority an audit report confirming that, after the change came into effect, the reconciliation participant continued to meet the requirements specified in clause 5.

(3) Despite clause 8(3), a reconciliation participant's certification is only deemed to be revoked if—
   (a) the reconciliation participant fails to give the advice required by subclause (2); or
   (b) the Authority advises the reconciliation participant that the Authority is not satisfied that the reconciliation participant continued to meet the requirements in clause 5 after the change came into effect.

(4) To avoid doubt, if this clause applies, the Authority must comply with clause 8(2).

10 Allocation by profile

If submission information is submitted as non half hour quantities to be allocated to trading periods by profile shape, the reconciliation manager must use the appropriate shape for the profile code contained in the submission information, if—
(a) the profile code has been approved by the market administrator 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
(c) the profile owner has authorised the reconciliation participant to use the approved profile code.

12 Application of profile shapes
The reconciliation manager must calculate the trading period information by applying the profile shape for the profile code specified in the submission file provided by the reconciliation participant if—
(a) the profile code has been approved by the market administrator 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 the profile owner has authorised the reconciliation participant to use the approved profile code; and
(c) if a balancing area shape is required as part of the profile, the initial residual or final residual profile shape as defined in Schedule 15.5 must be used.

13 Balancing area derived profiles approved in accordance with Appendix 1 of Schedule 15.5
The reconciliation manager must calculate the trading period information by applying 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 market administrator 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
(c) if the profile code had not been approved by the market administrator, or notified to the reconciliation manager, the reconciliation manager must use the final residual profile.

18 Calculation of scorecard rating

(4) Despite anything else in this Code, the scorecard rating must be set to 1 until such time as the Authority gives written notice to the participants that the scorecard rating will be calculated and applied in accordance with this clause.

Schedule 15.5
33 Profile maintenance and changes
(1) The profile sample must be representative of the profile population. The profile owner must be responsible for maintaining a valid statistical sample which takes into account changes in the profile population.
(2) The profile owner must maintain a current profile population list. The profile owner must inform the market administrator when an update is necessary (refer subclause (3)).
The **profile population** list is subject to random **audit** by the **market administrator** or its appointed **audit** agent.

(3) The **profile sample** must be updated when membership of the **profile population** has changed by more than 20% since the **sample date**. The **profile owner** must, no later than 10 **business days** after the **profile owner** becomes aware of such change in membership, give written notice to the **market administrator** of the changes in the **profile population** list. The **market administrator** must determine, and notify the **profile owner** of, any required modifications to the **profile sample**. The **profile owner** has 1 month from the date of notification by the **market administrator** to ensure that **certified half hour meters** are installed in the **metering installations** of these **ICP identifiers**, and that the **metering installations** are fully **certified**.

(4) If more than 5% of the **profile sample** has been lost or removed, the **profile owner** must submit to the **market administrator** a list of **ICP identifiers** in the current **profile sample** who have been lost or removed from the **profile population** list. The **market administrator** must draw **ICP identifiers** from the **profile population** list to replace those who are lost or removed from the **profile sample**. The **profile owner** must ensure that **certified half hour meters** are installed in the **metering installations** of these **ICP identifiers**, and that the **metering installations** are fully **certified**, no later than 1 month after the **market administrator** issues its determination of the appropriate replacement **ICP identifiers**.

(5) The addition or removal of **ICP identifiers** to or from the **profile sample** must follow the procedures in Appendix 2.

(6) There must be at least 3 months between updates.