Electricity Industry Participation Code 2010

Part 15
Reconciliation

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15.1 Contents of this Part
This Part provides for the following:
(a) the improvement of information about electricity conveyed as more volume information becomes available over time;
(b) the correction of information to remedy errors in information provided;
(c) how reconciliation participants must gather, store and provide information about electricity conveyed;
(d) how reconciliation participants must prepare and provide submission information;
(da) how dispatchable load purchasers must collect volume information in accordance with Schedule 15.2;
(e) how the reconciliation manager must calculate responsibility for electricity among reconciliation participants;
(f) how the reconciliation manager must pass information to the clearing manager, for the calculation of amounts owing under Part 14;
(g) obligations of the reconciliation manager to pass the information to reconciliation participants, the registry manager and the Authority;
(h) requirements for the creation, approval and maintenance of profiles;
(i) requirements for audits, approvals and certifications.

Compare: Electricity Governance Rules 2003 rule 1 part J

15.2 Requirement to provide complete and accurate information
(1) A participant must take all practicable steps to ensure that information that the participant is required to provide to any person under this Part is—
(a) complete and accurate; and
(b) not misleading or deceptive; and
(c) not likely to mislead or deceive.
(2) If a participant becomes aware that the information the participant provided under this Part does not comply with subclause (1)(a) to (c), even if the participant has taken all practicable steps to ensure that the information complies, the participant must, as soon as practicable, provide such further information as is necessary to ensure that the information complies with subclause (1)(a) to (c).

Compare: Electricity Governance Rules 2003 rule 1A part J

15.3 Provision of trading information at point of connection to network
(1) Unless a notice under clause 15.13 is in force, a trader must give the reconciliation manager a notice that complies with this clause at least 5 business days before the trader—
(a) commences trading electricity at a point of connection using a profile with a profile code other than HHR or RPS or UML or EG1 or PV1; or
(b) ceases trading electricity at a point of connection using a profile with a profile code other than HHR or RPS or UML or EG1 or PV1.

(2) A person giving a notice must ensure that the notice complies with any procedures or other requirements specified by the reconciliation manager.

(3) The reconciliation manager must give a copy of every notice to the clearing manager and system operator no later than 1 business day after receiving the notice.

Compare: Electricity Governance Rules 2003 rule 3 part J

15.4 Submission information to be delivered for reconciliation

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

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

Compare: Electricity Governance Rules 2003 rules 4.1.1 and 4.1.2 part J

15.5 Preparing and submitting submission information

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

(2) Each reconciliation participant must derive volume information in accordance with Schedule 15.2.

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

Compare: Electricity Governance Rules 2003 rules 4.1.3 and 4.1.4 part J
Clause 15.5(1) and (3): amended, on 5 October 2017, by clause 514(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

15.5A Dispatchable load purchaser must prepare dispatchable load information
(1) Each dispatchable load purchaser must prepare dispatchable load information using volume information prepared in accordance with Schedule 15.2.
(2) If clause 15.5B applies to a dispatch-capable load station's metering installation, the dispatchable load purchaser responsible for the dispatch-capable load station must comply with clause 15.5B in relation to the dispatch-capable load station.
Clause 15.5A(2): substituted, on 1 February 2016, by clause 94(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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.
Clause 15.5B: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 15.5B: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 15.5B(1) and (2)(b): amended, on 5 October 2017, by clause 515 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 15.5B(2): amended, on 1 February 2016, by clause 95(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

15.5C Aggregating and rounding dispatchable load information
(1) When preparing dispatchable load information, a dispatchable load purchaser must—
(a) aggregate volume information to the following level:
   (i) NSP code:
   (ii) dispatch-capable load station identifier:
(iii) **loss category** code:
(iv) **trading period**; and
(b) round the aggregated **volume information**—
(i) to 2 decimal places; and
(ii) so that if the digit to the right of the second decimal place is—
   (A) greater than or equal to 5, the second digit is rounded up; or
   (B) less than 5, the second digit is unchanged.

(2) When aggregating **volume information** for a **dispatch-capable load station** to the NSP, the **dispatchable load purchaser** must use the NSP code as shown in the registry at the time the **volume information** is derived.

Clause 15.5C: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**15.5D Dispatchable load information to be delivered to reconciliation manager**

(1) Each **dispatchable load purchaser** must provide to the **reconciliation manager**—
   (a) **dispatchable load information** for each GXP at which the **dispatchable load purchaser** has purchased **electricity** for a **dispatch-capable load station** during the **consumption period** immediately before each **reconciliation period**; and
   (b) if the **dispatchable load purchaser** knows that **dispatchable load information** previously provided has changed, revised **dispatchable load information** for the **consumption period** for which the **dispatchable load information** was initially provided.

(2) Each **dispatchable load purchaser** must provide—
   (a) the information described in subclause (1)(a) by 1600 hours on the 4th **business day** of each **reconciliation period**; and
   (b) the information described in subclause (1)(b) by 1600 hours on the 13th **business day** of each **reconciliation period**.

Clause 15.5D: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**Additional retailer and direct purchaser information**

**15.6 Retailer and direct purchaser ICP days information**

(1) Each **retailer** and **direct purchaser** (excluding **direct consumers**) must deliver a report to the **reconciliation manager** detailing the number of **ICP days** for each **NSP** for each submission file of **submission information** in respect of—
   (a) **submission information** for the immediately preceding **consumption period**, by 1600 hours on the 4th **business day** of each **reconciliation period**; and
   (b) revised **submission information** provided in accordance with clause 15.4(2), by 1600 hours on the 13th **business day** of each **reconciliation period**.

(2) The **retailer** or **direct purchaser** must calculate the **ICP days** information in subclause (1) using the data contained in the **retailer’s** or **direct purchaser’s** reconciliation system when it aggregates **volume information** for ICPs into **submission information**.

Compare: Electricity Governance Rules 2003 rule 4.2.1 part J
15.7 Retailer electricity supplied information
Each retailer must deliver to the reconciliation manager the retailer’s total monthly quantity of electricity supplied for each NSP, aggregated by invoice month, for which the retailer has provided submission information to the reconciliation manager, including revised submission information for that period as non loss adjusted values in respect of—
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period; and
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.
Compare: Electricity Governance Rules 2003 rule 4.2.2 part J

15.8 Retailer and direct purchaser half hourly metered ICPs monthly kWh information
Each retailer and direct purchaser (excluding direct consumers) must deliver to the reconciliation manager the retailer’s or direct purchaser’s total monthly quantity of electricity supplied for each half hourly metered ICP for which the retailer or direct purchaser has provided submission information to the reconciliation manager, including—
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period; and
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.
Compare: Electricity Governance Rules 2003 rule 4.2.3 part J

NSP information

15.9 Grid owner volume information
Each grid owner must deliver to the reconciliation manager, for each point of connection for all of its GXPs, the following:
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period:
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.
Compare: Electricity Governance Rules 2003 rule 4.3.1 part J

15.10 Participants to provide NSP submission information
A participant must provide the following information to the reconciliation manager for each NSP for which the participant has given a notice under clause 25(1) of Schedule 11.1:
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period; and
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.
Compare: Electricity Governance Rules 2003 rule 4.3.2 part J
Clause 15.10 heading: substituted, on 19 December 2014, by clause 40 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

15.11 Grid connected generator
Each generator who has a generating station or generating unit with a point of connection to the grid must deliver to the reconciliation manager for each of its points of connection—
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period; and
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.

Compare: Electricity Governance Rules 2003 rule 4.3.3 part J

15.12 Accuracy of submitted information
If a reconciliation participant submits information in accordance with this Code, and the reconciliation participant subsequently obtains more accurate information, the reconciliation participant must provide the most accurate information to the reconciliation manager or participant, as the case may be, at the next available opportunity for submission in accordance with clauses 15.20A, 15.27 and 15.28.

Compare: Electricity Governance Rules 2003 rule 4.4 part J

15.13 Notice by embedded generators
An embedded generator must give a notice to the reconciliation manager for an embedded generating station in relation to a point of connection for the purposes of clauses 15.3 and 15.5(3) if the embedded generator will not receive payment from the clearing manager or any other person for any electricity generated by the relevant embedded generation station through the point of connection to which the notice relates.

Compare: Electricity Governance Rules 2003 rule 4A part J

15.14 Notice of changes to the grid
(1) Each grid owner must give written notice to 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 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 extended reserve manager, 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. Compare: Electricity Governance Rules 2003 rule 5 part J

Notice of outage constraints or alternative supply

15.15 Notice 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 the reconciliation manager of the following:
(i) each point of connection to the grid that 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 had no load or generation connected to it in the modelling system; and
(b) each grid owner must give written notice to 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.

Compare: Electricity Governance Rules 2003 rule 6.1 part J

15.16 Balancing area NSP grouping changes
If an NSP has been affected by an outage constraint, and the reconciliation manager has determined the notice it receives in accordance with clause 24 of Schedule 11.1 is not compliant with that clause, the reconciliation manager must, no later than 10 business days after the date on which it determines the notice is not compliant, effect, in consultation with the relevant distributor, any changes that are, in the reconciliation manager’s opinion, necessary to balancing area NSP groupings that are to be used during the outage constraint.

Compare: Electricity Governance Rules 2003 rule 6.2 part J

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 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) if a reconciliation participant’s submission information has been affected by an outage constraint in a consumption period, and the reconciliation participant disputes or queries, in accordance with clause 15.24, the change to balancing area NSP groupings made in accordance with clause 15.16, the reconciliation manager must, no later than 10 business days after it determines that the notice it receives in accordance with clause 24 of Schedule 11.1 is not compliant, in consultation with the distributor, generator or purchaser concerned, assess whether a different balancing area NSP grouping would be more appropriate in the circumstances of the particular outage constraint. The reconciliation manager may change the alternative balancing area NSP grouping for the particular outage constraint and, if the alternative balancing area NSP grouping is changed, the reconciliation manager must update the information changed in accordance with clause 15.16 as necessary.

Compare: Electricity Governance Rules 2003 rule 6.3 part J
Clause 15.17(c) and (d): amended, on 5 October 2017, by clause 523(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

15.18 Reconciliation manager may request additional information
For the purpose of carrying out its role in accordance with this Code, the reconciliation manager may, in respect of a consumption period, give notice to a reconciliation participant that it requires such additional information from the reconciliation participant as the reconciliation manager reasonably requires, and the reconciliation participant must, as soon as practicable, provide such information to the reconciliation manager.

Compare: Electricity Governance Rules 2003 rule 7 part J
15.19 Seasonal adjustment and profiling
(1) The reconciliation manager must process submission information derived from non half hour volume information using a profile to allocate the non half hour submission information to trading periods in accordance with Schedule 15.4.
(2) Profiles must be established and changed (if necessary) in accordance with Schedule 15.5.
(3) For each reconciliation revision, the reconciliation manager must—
   (a) subject to paragraph (c), recalculate the seasonal adjustment shape for each reconciliation revision cycle; and
   (b) reconcile submission information using the latest profile shape published, and the most recently supplied profile information; and
   (c) recalculate the residual profile shape and any shapes approved as NSP derived profile shapes under clauses 19 to 24 of Schedule 15.5 for each reconciliation revision cycle and use the shape to allocate non half hour data across the trading periods, in accordance with Schedule 15.5; and
   (d) not recalculate the seasonal adjustment shape after the month 7 reconciliation revision.
(4) Subclause (3)(d) does not prevent the reconciliation manager from recalculating the seasonal adjustment shape following the month 7 reconciliation revision if necessary to resolve a dispute under clauses 14.25 or 15.29, or to correct information under clauses 15.21 to 15.26.

15.20 Calculation and allocation of unaccounted for electricity
The reconciliation manager must, in accordance with Schedule 15.4,—
   (a) calculate the scorecard rating of each retailer; and
   (b) calculate the unaccounted for electricity; and
   (c) allocate the unaccounted for electricity to, and balance, the total electricity supplied, for each NSP.

15.20A Reconciliation manager to update revised dispatchable load information
(1) This clause applies to any revised dispatchable load information provided under clause 15.5D(1)(b).
(2) The reconciliation manager must,—
   (a) if the dispatchable load information to which this clause applies relates to 1 or more consumption periods being 1, 3, 7, or 14 months before the current
reconciliation period, conduct a further update for each applicable consumption period; or

(b) if the dispatchable load information to which this clause applies relates to a consumption period other than the consumption periods set out in paragraph (a),—

(i) store the dispatchable load information until the consumption period becomes 1 of the consumption periods set out in paragraph (a); and

(ii) conduct a further update under paragraph (a).

(3) The reconciliation manager must not update revised dispatchable load information for a consumption period if 14 months have elapsed since the end of the consumption period.

(4) Subclause (3) does not prevent the correction of information under clauses 14.28, 15.26(2), or 15.29.


15.20B Reconciliation manager loss adjusts and summarises dispatchable load information

(1) The reconciliation manager must apply loss factors to dispatchable load information received under clause 15.5D—

(a) for each trading period; and

(b) using the loss category codes advised by the dispatchable load purchaser when submitting dispatchable load information under clause 15.5D.

(2) After applying loss factors under subclause (1), the reconciliation manager must summarise—

(a) into 1 file for each consumption period, dispatchable load information received under clause 15.5D(1)(a); and

(b) into 1 file for each consumption period, dispatchable load information received under clause 15.5D(1)(b) and updated under clause 15.20A.

(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).

(4) If the Authority makes a direction under subclause (3), the reconciliation manager must apply the values as loss factors to the relevant dispatchable load information for all reconciliation periods during which the direction applies.


15.20C Reconciliation manager to provide loss adjusted and summarised dispatchable load information to clearing manager

The reconciliation manager must provide to the clearing manager—

(a) the information described in clause 15.20B(2)(a) by 1600 hours on the 7th business day of each reconciliation period; and

(b) the information described in clause 15.20B(2)(b) by 1200 hours on the last business day of each reconciliation period.
15.20D Reconciliation manager to provide loss adjusted and summarised dispatchable load information to dispatchable load purchasers
At the same time the reconciliation manager provides the information described in clause 15.20C to the clearing manager, the reconciliation manager must provide each dispatchable load purchaser with the part of the information that relates to the dispatchable load purchaser.


Reconciliation information produced by reconciliation manager

15.21 Providing information specific to reconciliation participants
The reconciliation manager must provide information specific to each reconciliation participant and the clearing manager in accordance with Schedule 15.4.

Compare: Electricity Governance Rules 2003 rule 10.1 part J

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 related to 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.

Compare: Electricity Governance Rules 2003 rule 10.2 part J

15.23 Reconciliation information is not final

The reconciliation information provided in accordance with clauses 15.21 and 15.22 is subject to assessment in accordance with clauses 15.24 to 15.26.

Compare: Electricity Governance Rules 2003 rule 10.3 part J

15.24 Reconciliation information checked

(1) The reconciliation participant must check the accuracy of the reconciliation information provided by the reconciliation manager under clauses 15.21 and 15.22.

(2) The reconciliation participant may dispute the volume information on which the reconciliation information provided by the reconciliation manager under clauses 15.21 and 15.22 is based in accordance with clause 15.29.

Compare: Electricity Governance Rules 2003 rules 10.4 and 10.4A part J

15.25 Reconciliation manager must assess information not supplied

(1) If a reconciliation participant fails to provide any information to the reconciliation manager that the reconciliation participant is required to provide under this Part, the reconciliation manager must take all reasonable steps necessary to acquire or estimate the information, and in the case of missing trader data the reconciliation manager must—

(a) estimate a purchaser’s volume information by applying the ICP day scaling factor in accordance with Schedule 15.4; and

(b) estimate a generator’s volume information by using an estimated reading.

(2) Subclause (1) does not apply to information that the reconciliation manager is directed by the Authority to correct under clause 15.26(2).

Compare: Electricity Governance Rules 2003 rules 10.5 and 10.5A part J

15.26 Reconciliation manager to correct information

(1) If the reconciliation manager has, in accordance with clause 15.25(1), acquired or estimated information, or is unable to provide reconciliation information, it must, to the extent it is reasonable, attempt to subsequently establish the correct reconciliation information, provide the updated reconciliation information to the clearing manager and distribute the information to the reconciliation participants entitled to it in accordance with this Code.

(2) If the reconciliation manager considers that information provided by a reconciliation participant or a service provider under this Part is incorrect, the reconciliation manager must refer the issue to the Authority, and, if directed by the Authority to do so, take all reasonable steps to correct the information.

(3) A reconciliation participant or service provider must provide any information to the reconciliation manager that the reconciliation manager requires to correct information under subclause (2).

(4) If the reconciliation manager has corrected information under subclause (2), the reconciliation manager must provide the corrected information to the clearing manager and the reconciliation participants who are entitled to the information under this Code.
(5) The **reconciliation manager** must not correct information later than 24 months after the date on which information about an amount owing to which the incorrect information relates (if any) has been advised under Part 14.

Compare: Electricity Governance Rules 2003 rules 10.6 to 10.10 part J

Revisions

15.27 Reconciliation manager must reconcile revised information
(1) If the **reconciliation manager** receives revised NSP information or submission information that has been supplied to it since the previous reconciliation calculation in accordance with clauses 15.4(2) or 15.12, the **reconciliation manager** must reconcile the information in accordance with the following procedure:

(a) if the submission information received relates to 1 or more consumption periods being 1, 3, 7, or 14 months before the current reconciliation period, a further reconciliation must be conducted for that consumption period or those consumption periods:

(b) if the NSP information or submission information relates to any other consumption period, the **reconciliation manager** must store the information and wait until the consumption period becomes 1 of the consumption periods described in paragraph (a) before conducting a further reconciliation.

(2) The **reconciliation manager** must not reconcile revised NSP or submission information arising after month 14.

(3) Subclause (2) does not prevent the correction of information under clauses 14.28, 15.26(2) or 15.29.

Compare: Electricity Governance Rules 2003 rules 11.1 to 11.2A part J

15.28 Transitional provisions concerning revisions
(1) In this clause—

(a) “transitional revisions” means any revision carried out by the **reconciliation manager** in accordance with this clause, for any reconciliation period that includes a trading period that occurred before 1 May 2008; and

(b) “incumbent retailer” means, for each balancing area, the relevant retailer to be set out in the list of NSPs by balancing area and their corresponding retailers, published from time to time by the **reconciliation manager**, in accordance with subclause (3).

(2) The intent of this clause is—

(a) as far as practicable, to preserve the effect of the reconciliation provisions concerning revisions that were in effect immediately before 1 May 2008, for all transitional revisions; and

(b) to clarify that volume information and submission information for all transitional revisions (except as provided in this clause) must be submitted by reconciliation participants in accordance with this Part; and
(c) to clarify the application of certain clauses concerning disputes that existed before 1 May 2008.

(3) The reconciliation manager must publish a list of the incumbent retailers finalised under rule 11.4.3.2 of part J of the rules until all transitional revisions are completed.

(4) Despite anything in this Code—
   (a) to avoid doubt, clause 8 of Schedule 15.3 applies to submission information in relation to all transitional revisions; and
   (b) each reconciliation participant, including each incumbent retailer, must submit the required submission information relating to all transitional revisions in accordance with clause 15.4(2); and
   (c) if the submission information to be supplied for a transitional revision is the first such submission after 1 May 2008, the reconciliation participant must provide a full data set as if it were an initial submission in accordance with clause 15.4(1); and
   (d) in recognition of the fact that incumbent retailers have not, before 1 May 2008, been required to submit the submission information referred to in paragraph (b), the certification and audit requirements of Schedule 15.1 (required for activities in accordance with clauses 2 to 8 and 11 of Schedule 15.3, and clause 17 of Schedule 15.4), do not apply in relation to the non-half-hour metering information required to be submitted by incumbent retailers to the reconciliation manager for transitional revisions.

(5) Despite anything in this Code, all transitional revisions must be carried out by the reconciliation manager in accordance with this Code, subject to the following:
   (a) for the purposes of clause 7 of Schedule 15.4, the ICP scaling factor is 1; and
   (b) for the purposes of clauses 18(1)(b) and 19 of Schedule 15.4 the scorecard rating (SCri) for each retailer (other than the incumbent retailer) is 1; and
   (c) for the purposes of clause 19 of Schedule 15.4, at each NSP the market share proportion (MSRi) for the incumbent retailer is 1, and, for all other retailers, is 0.

(6) Despite anything in this Code, all disputes concerning metering installations or consumption information in relation to transitional revisions—
   (a) that existed before 1 May 2008 are not affected by the coming into effect of part J of the rules and this Part; and
   (b) must be commenced no later than 2 years after the date of issue of any invoice to which the disputed information relates.

(7) Despite anything in this Code—
   (a) as soon as practicable after 16 October 2008, the reconciliation manager must publish 1 seasonal adjustment shape for each balancing area that existed at the beginning of the 1st trading period of May 2008; and
   (b) the reconciliation manager must not publish any further seasonal adjustment shapes for the consumption periods for which transitional revisions are required; and
(c) no later than 5 business days after the date on which those seasonal adjustment shapes are published, each reconciliation participant must provide submission information to the reconciliation manager based on those seasonal adjustment shapes for the months of February to July 2008; and

(d) as soon as practicable after the expiry of the time referred to in paragraph (c) the reconciliation manager must complete revisions using that submission information for the months of February 2008 to July 2008; and

(e) each reconciliation participant must continue to use the seasonal adjustment shapes published by the reconciliation manager under paragraph (a) for all subsequent transitional revisions for the period for which transitional revisions are required.

Compare: Electricity Governance Rules 2003 rule 11.4 part J

15.29 Volume information disputes

(1) A reconciliation participant may commence a dispute relating to volume information by notice in writing to the reconciliation manager.

(2) A reconciliation participant may not give written notice of a dispute under subclause (1) if information about an amount owing based on the volume information has been advised under Part 14.

(3) The reconciliation manager must give written notice to the Authority and all participants affected by the dispute no later than 1 business day after receiving notice of the dispute under subclause (1).

(4) On receiving a notice of a dispute under subclause (3), the Authority may direct that no further action be taken in respect of the dispute.

(5) If the Authority gives a direction under subclause (4), subclauses (6) to (13) cease to apply to the dispute. However, a direction under subclause (4) does not affect the validity of a washup conducted under clauses subpart 6 of Part 14 before the direction was given.

(6) The disputing reconciliation participant and the reconciliation manager must use reasonable endeavours to resolve the dispute.

(7) A dispute does not excuse anyone from complying with this Code.

(8) Participants must continue to use disputed volume information as if it were not in dispute while the dispute is being resolved.

(9) If a dispute is not resolved within 15 business days after the date on which the reconciliation manager received notice of the dispute under subclause (1), the disputing reconciliation participant or the reconciliation manager may refer the dispute to the Rulings Panel for resolution under the Act.

(10) The Rulings Panel may make such determination as it thinks fit.

(11) The Rulings Panel must give written notice of its determination to the disputing reconciliation participant and affected participants.

(12) If the dispute is resolved by the parties to the dispute agreeing, or the Rulings Panel determining, that the volume information is incorrect, the reconciliation manager must correct the volume information as follows:
(a) if a revised **seasonal adjustment shape** must be issued in order for the **volume information** to be corrected—

(i) the **reconciliation manager** must provide each **reconciliation participant** whose **submission information** is required to be corrected with a revised **seasonal adjustment shape**; and

(ii) each **reconciliation participant** must provide corrected **submission information** to the **reconciliation manager** no later than 4 **business days** after being provided with the revised **seasonal adjustment shape**:

(b) if a revised **seasonal adjustment shape** does not need to be issued in order for the **volume information** to be corrected, each **reconciliation participant** whose **volume information** or **dispatchable load information** is required to be corrected must provide corrected relevant information to the **reconciliation manager** no later than 4 **business days** after receiving notice of the resolution of the dispute.

(13) The **reconciliation manager** must provide the corrected **volume information** to the **clearing manager**.

(14) **[Revoked]**

Compare: Electricity Governance Rules 2003 rule 12 part J
Clause 15.29(5): amended, on 24 March 2015, by clause 13(1) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.
Clause 15.29(14): revoked, on 24 March 2015, by clause 13(2) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.

**Reporting obligations of the reconciliation manager**

15.30 **[Revoked]**

Compare: Electricity Governance Rules 2003 rule 13.1 part J

15.31 **Right to information concerning reconciliation manager's actions**

(1) **A reconciliation participant** may, by giving written notice to the **reconciliation manager**, request further information related to—
(a) any alleged breach of this Code by the reconciliation manager;
(b) any alleged breach of this Part by a reconciliation participant, if the alleged breach has materially affected the reconciliation participant requesting the information.

(2) The reconciliation manager must, no later than 10 business days after receiving such a request, provide the requested information to the reconciliation participant, provided that the information does not include any information that is confidential in respect of any other person.

Compare: Electricity Governance Rules 2003 rule 13.2 part J

15.32 Reconciliation reports
The reconciliation manager must report to the Authority and each reconciliation participant, the information determined during the reconciliation process as described in clauses 24 to 28 of Schedule 15.4.

Compare: Electricity Governance Rules 2003 rule 13.3 part J

15.33 [Revoked]

Compare: Electricity Governance Rules 2003 rule 14 part J

15.34 Use of agents by reconciliation participants
(1) A reconciliation participant who has obligations under this Part may discharge those obligations by way of an agent.

(2) A reconciliation participant who utilises an agent to discharge an obligation under this Code remains responsible and liable for, and is not in any way released from, that obligation.

(3) A reconciliation participant must not assert, against anyone, that it is not responsible or liable for its obligations because the reconciliation participant’s agent has done or not done something or has failed to meet a relevant standard.

Compare: Electricity Governance Rules 2003 rule 15 part J

15.35 Provision of information
(1) If an obligation exists to provide information in accordance with this Part, a participant must deliver that information to the required person within the timeframe specified in this Code, or, in the absence of any such timeframe, within any timeframe the Authority specifies in writing.

(2) Such information must be delivered in the format determined from time to time by the Authority.

(3) Unless otherwise specified in this Part, information that must be provided under this Part by the registry manager or to the registry manager, must be provided using the registry.
15.36 New Zealand Daylight Time adjustment techniques

(1) Submission information provided to, and reconciliation information provided by, the reconciliation manager must, if applicable, be adjusted for NZDT using the technique set out in subclause (3) specified by the Authority.

(2) Any information exchanged between participants that contains trading period specific data must, if applicable, be adjusted for NZDT in accordance with subclause (3).

(3) A daylight savings adjustment must be made by using the “trading period run on technique”, which requires that daylight saving adjustment periods are allocated as consecutive trading periods within the relevant day, in the sequence that they occur.

(4) If no adjustment is made in accordance with subclause (3) to information exchanged between reconciliation participants that contains trading period specific data, the code “NZST” must be used within the data transfer file.

Compare: Electricity Governance Rules 2003 rule 17 part J

15.37 [Revoked]

Compare: Electricity Governance Rules 2003 rule 18 part J
Clause 15.37: revoked, on 1 June 2017, by clause 24 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

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

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


15.37B Retailers to arrange for audits in respect of distributed unmetered load

Each retailer that is responsible for distributed unmetered load must arrange for an audit to be carried out in accordance with Part 16A in respect of the distributed unmetered load that verifies that—

(a) the retailer's distributed unmetered load database complies with clause 11 of Schedule 15.3; and
(b) the information recorded in the retailer's distributed unmetered load database is complete and accurate; and
(c) volume information for the distributed unmetered load is being calculated accurately and profiles have been correctly applied.

Clause 15.37B: inserted, on 1 June 2017, by clause 25 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
15.37C Authority and participant requested audits

(1) The Authority may at any time carry out, or appoint an auditor to carry out, an audit of a participant in respect of the participant's obligations under this Part.

(2) If a participant considers that another participant may not have complied with this Part, the participant may request that the Authority carry out, or appoint an auditor to carry out, an audit of the other participant.

(3) Part 16A applies to an audit carried out under this clause.

Clause 15.37C: inserted, on 1 June 2017, by clause 25 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

15.38 Functions requiring certification

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

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

(b) gathering and storing raw meter data:

(c) creating and managing (including validating, estimating, storing, correcting and archiving)—

(i) half hour volume information; or

(ii) non half hour volume information; or

(iii) half hour and non half hour volume information; or

(iv) dispatchable load information:

(d) delivery of:

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

(ii) electricity supplied information under clause 15.7:

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

(da) [Revoked]

(db) [Revoked]

(e) provision of submission information for reconciliation:

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

(1A) A dispatchable load purchaser must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
(a) gathering and storing raw meter data:
(b) creating and managing (including validating, estimating, storing, correcting, and archiving)—
   (i) half hour volume information; or
   (ii) non half hour volume information; or
   (iii) half hour and non half hour volume information; or
   (iv) dispatchable load information:
  (c) providing dispatchable load information.

15.38(1B) For the purposes of subclause (1A), each reference to a reconciliation participant in Schedule 15.1 is to be read as a reference to a dispatchable load purchaser.

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rule 19 part J
Clause 15.38(1)(a) and (f): amended, on 1 November 2018, by clause 118(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Clause 15.38(1)(da) and (db): inserted, on 19 December 2014, by clause 41 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.
Clause 15.38(1)(da) and (db): revoked, on 1 February 2016, by clause 99(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 15.38(1A): inserted, on 1 May 2014, by clause 101(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 15.38(1B): inserted, on 1 May 2014, by clause 101(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 15.38(2): revoked, on 1 June 2017, by clause 26(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

Participant identifiers


15.39 Participants must use participant identifiers

(1) Each participant must use its participant identifier, when required, to correctly identify that participant’s information.

(2) A participant must apply to the Authority in the prescribed form for a participant identifier at least 5 business days before the participant identifier is required.

(3) The Authority may, by giving written notice to any participant, change the participant identifier for that participant. If the Authority does this, the new participant identifier for that participant will become effective from the date specified in the relevant notice.

Compare: Electricity Governance Rules 2003 rule 20 part J
Schedule 15.1 Certification processes

c15.38


1 Contents of this Schedule

This Schedule sets out—

(a) [Revoked]

(b) the requirement for reconciliation participants to be certified to perform the functions specified in clause 15.38, and the process for obtaining and renewing that certification.

(c) [Revoked]

Compare: Electricity Governance Rules 2003 clause 1 schedule J1
Clause 1(a): revoked, on 1 June 2017, by clause 28(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 1(b): amended, on 1 June 2017, by clause 28(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 1(c): revoked, on 1 June 2017, by clause 28(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

2 [Revoked]

Compare: Electricity Governance Rules 2003 clause 1A schedule J1

2A Requirement for certification

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

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

(b) in every other case, the later of—
    (i) 6 months after the date on which the reconciliation participant first performs a function specified in clause 15.38(1); or
    (ii) the date on which the reconciliation participant is recorded in the registry as being responsible for 100 or more ICPs of the kind described in subclause (2).

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

(a) 1 or more category 1 metering installations and no other kind of metering installation; and

(b) no unmetered load.

Clause 2A: inserted, on 1 June 2017, by clause 29 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
2B Reconciliation participants to obtain Authority approval before performing certain functions

(1) A reconciliation participant that proposes to perform a function listed in clause 15.38(1) without obtaining certification (in reliance on clause 2A) must obtain the Authority's prior approval.

(2) The Authority must give its approval if it is satisfied, on the basis of information provided to it by the reconciliation participant, that the reconciliation participant complies with such of the requirements specified in subclause (3) as are relevant to the reconciliation participant.

(3) The requirements are that the reconciliation participant must—
   (a) be capable of producing submission information accurately;
   (b) be capable of performing the functions described in clause 15.38(1)(d):
   (c) be capable of switching an ICP in accordance with Schedule 11.3:
   (d) be capable of managing an ICP in accordance with Schedule 11.1:
   (e) understand its obligations under this Code.

Clause 2B: inserted, on 1 June 2017, by clause 29 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

3 Performance of reconciliation participant’s obligations by agent

A reconciliation participant may perform any obligation under this Schedule by an agent, and for that purpose, every act or omission of a reconciliation participant’s agent is deemed to be an act or omission of the reconciliation participant.

Compare: Electricity Governance Rules 2003 clause 1B schedule J1

4 Obtaining certification

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

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

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

Compare: Electricity Governance Rules 2003 clauses 3.1 to 3.1B schedule J1

5 Granting certification

(1) The Authority must grant certification to a reconciliation participant only if—
   (a) the Authority is satisfied, on the basis of an audit report provided to the Authority under Part 16A, that the reconciliation participant meets the requirements relevant to the functions specified in clause 15.38 for which the reconciliation participant is seeking certification.

   (b) [Revoked]

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

(3) [Revoked]

Compare: Electricity Governance Rules 2003 clause 3.2 schedule J1
Clause 5(1)(a): amended, on 1 June 2017, by clause 30(1)(a) and (b) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 5(1)(b): revoked, on 1 June 2017, by clause 30(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 5(3): revoked, on 1 June 2017, by clause 30(3) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

6 Lists of certified reconciliation participants
The Authority must publish, and keep updated—
(a) a list of certified reconciliation participants that includes, for each reconciliation participant, the date on which the certification expires.
(b) [Revoked]

Compare: Electricity Governance Rules 2003 clause 3A schedule J1

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

Compare: Electricity Governance Rules 2003 clause 3B schedule J1
Clause 7: amended, on 1 June 2017, by clause 32(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 7(2): amended, on 1 June 2017, by clause 32(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

8 Changes that affect certification
(1) [Revoked]
(1A) If there is a material change to a reconciliation participant's systems or processes such that an audit is required under clause 16A.11, the Authority must, on receiving the audit report required by that clause, decide whether to continue the reconciliation participant's certification.
(2) The Authority must, by notice to the reconciliation participant, continue the reconciliation participant’s certification if the Authority is satisfied that the reconciliation participant will continue to meet the requirements in clause 5 after the change has come into effect.
(3) A reconciliation participant’s certification is revoked if—
(a) a reconciliation participant fails to provide an audit report to the Authority in accordance with clause 16A.11; or
(b) the **Authority** gives written notice to the **reconciliation participant** that the **Authority** is not satisfied that the **reconciliation participant** will continue to meet the requirements in clause 5 after the change has come into effect.

Compare: Electricity Governance Rules 2003 clause 3C schedule J1
Clause 8(1A): inserted, on 1 June 2017, by clause 33(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**8A [Revoked]**
Clause 8A: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**9 [Revoked].**
Compare: Electricity Governance Rules 2003 clause 5 Schedule J1
Clause 9: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**10 [Revoked]**
Compare: Electricity Governance Rules 2003 clause 6 schedule J1
Clause 10: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**11 [Revoked]**
Compare: Electricity Governance Rules 2003 clause 6A schedule J1
Clause 11: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**12 [Revoked]**
Compare: Electricity Governance Rules 2003 clauses 8.1 and 8.1A schedule J1
Clause 12: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**13 [Revoked]**
Compare: Electricity Governance Rules 2003 clause 8.2 schedule J1
Clause 13: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**14 [Revoked]**
Compare: Electricity Governance Rules 2003 clause 8.2A schedule J1
Clause 14: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
15 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.3 schedule J1
Clause 15: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

16 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.4 schedule J1
Clause 16: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.5 schedule J1
Clause 17: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

18 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.6 schedule J1
Clause 18: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

19 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.7 schedule J1
Clause 19: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Schedule 15.2
Collection of volume information

1 Contents of this Schedule
This Schedule establishes the required processes, in so far as they relate to the reconciliation process, for—
(a) collecting raw meter data, interrogating meters, and deriving validated meter readings; and
(b) creating estimated readings and permanent estimates; and
(c) deriving volume information from validated meter readings, estimated readings, and permanent estimates; and
(d) supporting data processing activities.

Compare: Electricity Governance Rules 2003 clause 1 schedule J2

2 Collection of raw meter data by certified reconciliation participant
(1) This clause applies to each metering installation for which a metering equipment provider is responsible, except for a metering installation—
(a) that only the metering equipment provider can electronically interrogate; or
(b) for which the metering equipment provider has an arrangement with the reconciliation participant, which prevents the reconciliation participant from electronically interrogating the metering installation.

(2) A reconciliation participant must obtain raw meter data used to determine volume information—
(a) from the services access interface of the metering installation; or
(b) if the raw meter data can only be obtained from the metering equipment provider’s back office, from the metering equipment provider.

(3) A reconciliation participant must ensure that the interrogation cycle for each metering installation that it interrogates does not exceed the maximum interrogation cycle in the registry.

(4) A reconciliation participant must interrogate a metering installation at least once in each maximum interrogation cycle for the metering installation.

(5) A reconciliation participant must, when electronically interrogating a metering installation,—
(a) ensure that the interrogation and processing system electronically monitors and corrects its internal clocks against a time source with a verifiable standard at a frequency sufficient, but no longer than 1 week, to ensure the internal clock is accurate, when carrying out an interrogation, to within ±5 seconds of—
(i) New Zealand standard time; or
(ii) New Zealand daylight time; and
(b) compare the time on the internal clock of the data storage device with the time on the interrogation and processing system clock; and
(c) calculate the time error for the data storage device; and
(d) if the time error calculated under paragraph (c) is equal to or less than the applicable time error set out in Table 1, correct the clock of the data storage device; and

(e) if the time error calculated under paragraph (c) is greater than the applicable time error set out in Table 1,—
   (i) correct the clock of the data storage device; and
   (ii) compare the time of the clock with the time of the interrogation and processing system clock; and
   (iii) correct any affected raw meter data; and

(f) download the event log.

(6) The reconciliation participant must record in the interrogation and processing system logs, the time, the date, and the extent of any change in the internal clock setting in the metering installation.

Table 1: Maximum permitted time errors

<table>
<thead>
<tr>
<th>Metering installation category</th>
<th>Half-hour metering installations (seconds)</th>
<th>Non half-hour metering installations (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>±30</td>
<td>±60</td>
</tr>
<tr>
<td>2</td>
<td>±10</td>
<td>±60</td>
</tr>
<tr>
<td>3</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>4</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>5</td>
<td>±5</td>
<td>NA</td>
</tr>
</tbody>
</table>

Source of volume information

(1) A meter reading must, in accordance with the relevant reconciliation participant’s certified processes and procedures, and using its certified facilities, be sourced directly from raw meter data, and if appropriate, be derived and calculated from financial records.

(2) A validated meter reading must be derived from a meter reading. A meter reading that is provided by a consumer may be used as a validated meter reading only if another set of validated meter readings that has not been provided by the consumer is used during the validation process specified in clauses 16 and 17.

(3) An estimated reading and a permanent estimate must be clearly identified as an estimate at source and in an exchange of metering data or volume information between participants (excluding the reconciliation manager).

(4) Volume information must be directly derived, in accordance with this Schedule, from—
   (a) validated meter readings; or
   (b) estimated readings; or
   (c) permanent estimates.
(5) A reconciliation participant must ensure that all raw meter data used to derive volume information in accordance with this Schedule is not rounded or truncated from the stored data from the metering installation.
Compare: Electricity Governance Rules 2003 clause 3 schedule J2

4 Permanence for the purposes of reconciliation
(1) Only volume information created using validated meter readings, or if such values are unavailable, permanent estimates, has permanence within the reconciliation processes (unless subsequently found to be in error).
(2) The relevant reconciliation participant must, at the earliest opportunity, and no later than the month 14 revision cycle, replace volume information created using estimated readings with volume information created using validated meter readings.
(3) If, despite having used reasonable endeavours for at least 12 months, a reconciliation participant has been unable to obtain a validated meter reading, the reconciliation participant must replace volume information created using an estimated reading with volume information created using a permanent estimate in place of a validated meter reading.
Compare: Electricity Governance Rules 2003 clause 4 schedule J2
Clause 4(2) and (3): replaced, on 1 February 2019, by clause 119(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

5 Meter interrogation for non half hour metering

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.
Compare: Electricity Governance Rules 2003 clause 5.1 schedule J2

6 When non half hour meter readings apply
Non half hour meter readings are deemed to apply—
(a) if the non half hour meter reading is also a switch event meter reading—
   (i) for the gaining trader, from 0000 hours on the day of the relevant event date; and
   (ii) for the losing trader, at 2400 hours at the end of the day before the relevant event date; or
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(b) in all other cases, from 0000 hours on the day after the last meter interrogation up to and including 2400 hours on the day of the meter interrogation.

Compare: Electricity Governance Rules 2003 clause 5.2 schedule J2

7 Non half hour meter reading during period of supply

(1) Each reconciliation participant must ensure that a validated meter reading is obtained in respect of every meter register for every non half hour metered ICP for which it is responsible, at least once during the period of supply to the ICP by the reconciliation participant, and used to create volume information. This may be a validated meter reading at the time the ICP is switched to, or from, the reconciliation participant.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

Compare: Electricity Governance Rules 2003 clauses 5.3 and 5.3A schedule J2

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 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 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 Authority’s assessment, is reasonable.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

Compare: Electricity Governance Rules 2003 clauses 5.4 and 5.4A schedule J2
Clause 8(1): amended, on 5 October 2017, by clause 532(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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—
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(a) each reconciliation participant must report to the 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 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.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

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

Compare: Electricity Governance Rules 2003 clauses 5.5 and 5.5A schedule J2

10 Interrogation log
To verify the accuracy of raw meter data collected during interrogation of non half hour metering, a log must be produced consisting of the following as a minimum:

(a) the means to establish the identity of the individual meter reader:
(b) the ICP identifier, and the meter and register identification:
(c) the method being used for this interrogation and the device ID of equipment being used for interrogation of the meter:
(d) the date and time of the meter interrogation.

Compare: Electricity Governance Rules 2003 clause 5.6 schedule J2

11 Metering installation that is electronically interrogated
(1) A reconciliation participant must, as required under clause 2(2), obtain raw meter data from the services access interface for an electronically interrogated metering installation. This may be carried out through the use of portable devices or remotely by the use of a recognised communications medium.

(2) Raw meter data obtained by the electronic interrogation of a metering installation must consist of the following as a minimum:

(a) the unique identifier of the data storage device in the metering installation:
(b) the time from the data storage device at the commencement of the download, unless the time is within specification and the interrogation log automatically records the time of interrogation:
(c) the metering information, which represents the quantity of electricity conveyed at the point of connection, including the date and time stamp or index marker for each half hour period. This may be limited to the metering information accumulated since the last interrogation:
(d) the event log, which may be limited to the events information accumulated since the last interrogation:
for all metering information, an interrogation log generated by the interrogation software to record details of all interrogations. The reconciliation participant responsible for collecting the data must peruse the interrogation log and take appropriate action if problems are apparent. Alternatively, this process may be an automated software function that flags exceptions.

(3) For the purposes of subclause (2)(e), the interrogation log must form part of the interrogation audit trail and must contain the following as a minimum:
(a) the date of interrogation:
(b) the time of commencement of interrogation:
(c) the operator identification (if available):
(d) the unique identifier of the data storage device:
(e) the time errors outside the range specified in Table 1 of clause 2:
(f) the method of interrogation:
(g) the identifier of the reading device used for interrogation (if applicable).

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J2

12 [Revoked]

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J2
Clause 12 and Table 1: revoked, on 29 August 2013, by clause 27 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

13 Trading period
The trading period duration, which is normally 30 minutes, must be within ±0.1% (± 2 seconds).

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J2

14 Quantification error
[Revoked]

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J2

15 Half hour estimates
(1) If a reconciliation participant is unable to interrogate an electronically interrogated metering installation before the deadline for providing submission information or dispatchable load information, the reconciliation participant must submit to the reconciliation manager its best estimate of the quantity of electricity that was purchased or sold in each trading period during any applicable consumption period for that metering installation.

(2) The reconciliation participant must use reasonable endeavours to ensure that estimated submission information is within the percentage specified by the Authority.
Validation

16 Non half-hour meter readings and estimated readings

(1) All non half-hour meter readings and estimated readings must be checked for validity by the relevant reconciliation participant after each interrogation.

(2) Each validity check of non half-hour meter readings and estimated readings must include the following:
   (a) confirmation that the meter reading or estimated reading relates to the correct ICP, meter, and register;
   (b) checks for invalid dates and times;
   (c) confirmation that the meter reading or estimated reading lies within an acceptable range compared with the expected pattern, previous pattern or trend;
   (d) confirmation that there is no corruption of the data, including unexpected 0 values.

Compare: Electricity Governance Rules 2003 clause 7.1 schedule J2

17 Electronic meter readings and estimated readings

(1) All meter readings obtained by electronic interrogation and estimated readings must be checked for validity by the relevant reconciliation participant.

(2) Each validity check of a meter reading obtained by electronic interrogation and each estimated reading must be at a frequency that will allow a further interrogation of the data storage device before the data is overwritten within the data storage device and before the data can be used for any purpose under this Code.

(3) [Revoked]

(4) Each validity check of a meter reading obtained by electronic interrogation or an estimated reading must include the following:
   (a) checks for missing data;
   (b) checks for invalid dates and times;
   (c) checks of unexpected 0 values;
   (d) comparison with expected or previous flow patterns;
   (e) comparison of meter readings with data on any data storage device registers that are available:
   (f) a review of meter and data storage device event log. Any event that could have affected the integrity of metering data must be investigated.

Compare: Electricity Governance Rules 2003 clause 7.2 schedule J2
18 Archiving and storing of raw meter data

(1) A reconciliation participant who is responsible for interrogating a metering installation under this Part must archive all raw meter data downloaded or collected, and any changes to the raw meter data, for not less than 48 months in accordance with clause 8(6) of Schedule 10.6 with all necessary amendments.

(2) Each reconciliation participant must ensure that procedures are in place to ensure that raw meter data for which it is responsible cannot be accessed by unauthorised personnel.

(3) Each reconciliation participant must ensure that meter readings cannot be modified without an audit trail being created.

Compare: Electricity Governance Rules 2003 clause 8 schedule J2


19 Correction of meter readings

(1) If a reconciliation participant detects errors while validating non half hour meter readings, the reconciliation participant must—
   (a) confirm the original meter reading by carrying out another meter reading; and
   (b) if the second meter reading confirms that the original meter reading is erroneous, replace the original meter reading with the second meter reading (even if the second meter reading is at a different date).

(1A) If a reconciliation participant detects errors while validating non half hour meter readings, but the reconciliation participant cannot confirm the original meter reading or replace it with a meter reading from another interrogation, the reconciliation participant must—
   (a) substitute the original meter reading with an estimated reading that is marked as an estimate; and
   (b) subsequently replace the estimated reading in accordance with clause 4(2).

(2) If a reconciliation participant detects errors while validating half-hour meter readings, the reconciliation participant must correct the meter readings as follows:
   (a) if the relevant metering installation has a check meter or data storage device, substitute the original meter reading with data from the check meter or data storage device; or
   (b) if the relevant metering installation does not have a check meter or data storage device, substitute the original meter reading with data from another period provided—
      (i) the total of all substituted intervals matches the total consumption recorded on a meter, if available; and
      (ii) the reconciliation participant considers the pattern of consumption to be materially similar to the period in error.

(3) A reconciliation participant may use error compensation and loss compensation as part of the process of determining accurate data. Whatever methodology is used, the reconciliation participant must document the compensation process and comply with audit trail requirements set out in this Code.
(4) In correcting a meter reading in accordance with this clause, a reconciliation participant must not overwrite the raw meter data. If the raw meter data and the meter readings are the same, the reconciliation participant must use the processing or data correction application to—
(a) make an automatic secure backup of the affected data; and
(b) archive the affected data.

(5) If a reconciliation participant corrects or alters data under this clause, the reconciliation participant must generate and archive a journal that contains the following information:
(a) the date of the correction or alteration; and
(b) the time of the correction or alteration; and
(c) the operator identifier for the person within the reconciliation participant who made the correction or alteration; and
(d) the half hour meter reading data or the non half hour meter reading data corrected or altered, and the total difference in volume of such corrected or altered data; and
(e) the technique used to arrive at the corrected data; and
(f) the reason for the correction or alteration.

20 Data transmission
Transmissions and transfers of data related to metering between reconciliation participants or reconciliation participant’s agents, for the purposes of this Code, must be carried out electronically, using systems that ensure the security and integrity of the data transmitted and received.

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

(2) The audit trail must—
(a) include details of information—
   (i) provided to and received from the registry manager; and
   (ii) provided to and received from the reconciliation manager; and
   (iii) provided and received from other reconciliation participants and their agents; and
(b) cover all raw meter data and any changes to the raw meter data archived under clause 18.

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

(4) Logs must be printed and filed as hard copy or maintained as data files, in a secure form, along with other archived information, and must include (at a minimum) the following:
(a) an activity identifier; and  
(b) the date and time of the activity; and  
(c) the operator identifier for the person within the reconciliation participant who performed the activity.

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

Compare: Electricity Governance Rules 2003 clause 11.1 to 11.3 schedule J2
Clause 21(2)(b): substituted, on 29 August 2013, by clause 33(a) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

22 [Revoked]

Compare: Electricity Governance Rules 2003 clause 11.4 schedule J2
Schedule 15.3
Calculation and provision of submission information

1 Contents of this schedule
This Schedule provides for—
(a) the processing of raw meter data and supporting information to create submission information; and
(b) the delivery of submission information to the reconciliation manager.
Compare: Electricity Governance Rules 2003 clause 1 schedule J3

Creation of submission information

2 Reconciliation participants to prepare information
(1) If a reconciliation participant is required to prepare submission information for an NSP for the relevant consumption period in accordance with this Code, the submission information for each ICP about which information is provided under clause 11.7(2)—
(aa) must comprise all volume information for the ICP:
(a) must comprise half hour volume information for the total metered quantity of electricity for each category 3 or higher metering installation:
(ab) must not comprise half hour volume information for a non half-hour metering installation:
(ac) must comprise either half hour volume information or non half hour volume information for the total metered quantity of electricity for each metering installation that—
(i) is a category 1 metering installation or category 2 metering installation; and
(ii) is a half-hour metering installation:
(ad) must comprise non half hour volume information calculated under clauses 4 to 6 (as applicable) for the total metered quantity of electricity for each metering installation that—
(i) is a category 1 metering installation or category 2 metering installation; and
(ii) contains only non half-hour metering:
(ac) if a metering installation is a category 1 metering installation or category 2 metering installation, and the metering installation contains half-hour metering and non half-hour metering, may comprise—
(i) a combination of—
(A) half hour volume information for the half-hour metering; and
(B) non half hour volume information calculated under clauses 4 to 6 (as applicable) for the non half-hour metering; or
(ii) non half hour volume information for the total metered quantity of electricity for the metering installation:
(b) [Revoked]
(c) must include unmetered load quantities for each ICP that has unmetered load associated with it, which must be derived from the quantity recorded in the
registry against the relevant ICP and the number of days in the period, the distributed unmetered load database, or other sources of relevant information.

(1A) However, a reconciliation participant need not comply with subclause (1)(a) to (ae) if—
(a) the reconciliation participant is using a profile approved in accordance with Schedule 15.5; and
(b) the approved profile allows the reconciliation participant to prepare submission information that does not comply with subclause (1)(a) to (ae); and
(c) the reconciliation participant complies with the submission information requirements set out in the approved profile.

(2) To create non half hour submission information, a reconciliation participant must only use information that is dependent on a control device if—
(a) the certification of the control device is recorded in the registry; or
(b) the metering installation in which the control device is located is an interim certified metering installation.

(3) To create submission information for a point of connection for which it is responsible, a reconciliation participant must use volume information from each metering installation for the point of connection.

(4) For the purposes of subclause (3), the reconciliation participant must calculate the volume information by applying to the raw meter data obtained from each metering installation—
(a) for each ICP, the compensation factor recorded in the registry for the metering installation; or
(b) for each NSP, the compensation factor recorded in the metering installation’s most recent certification report.

3 Historical estimates and forward estimates

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

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

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

Compare: Electricity Governance Rules 2003 clause 2.2 schedule J3

## 4 Historical estimates with seasonal adjustment

The methodology that must be used by each **reconciliation participant** to prepare an **historic estimate** of **volume information** for each **ICP** when the relevant **seasonal adjustment shape** is available, is as follows:

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

\[
HE_{ICP} = \frac{kWh_P \times A}{B}
\]

where

- \(HE_{ICP}\) is the quantity of **electricity** allocated to a **consumption period** for an **ICP**
- \(kWh_P\) is the difference in kWh between the last **validated meter reading** before the **consumption period** and the 1\(^{st}\) **validated meter reading** after the **consumption period**
- \(A\) is the sum of the **seasonal adjustment shape** values for the **consumption period**
- \(B\) is the sum of the **seasonal adjustment shape** values for the same time period as is covered by \(kWh_P\) as published by the **reconciliation manager**:

(b) if the period between any 2 consecutive **validated meter readings** encompasses the 1\(^{st}\) part of a **consumption period** and the period between the 2\(^{nd}\) **validated meter reading** and the subsequent **validated meter reading** encompasses the rest of that **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

\[
HE_{ICP} = \frac{kWh_{P1} \times A_1}{B_1} + \frac{kWh_{P2} \times A_2}{B_2}
\]

where

- \(HE_{ICP}\) is the quantity of **electricity** allocated to a **consumption period** for an **ICP**
kWh_{P1} is the difference in kWh between the last validated meter reading before the consumption period and the validated meter reading during the consumption period.

A_1 is the sum of the seasonal adjustment shape values for the relevant days in the 1st part of the consumption period.

B_1 is the sum of the seasonal adjustment shape values for the same time period as is covered by kWh_{P1}.

kWh_{P2} is the difference in kWh between the first validated meter reading during the consumption period and the 1st validated meter reading after the consumption period.

A_2 is the sum of the seasonal adjustment shape values for the relevant days in the latter part of the consumption period.

B_2 is the sum of the seasonal adjustment shape values for the same time period as is covered by kWh_{P2}.

Compare: Electricity Governance Rules 2003 clauses 2.2.1 schedule J3

5 Historical estimates without seasonal adjustment

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

(a) within the consumption period; and
(b) within the period covered by kWh_{Px}.

Compare: Electricity Governance Rules 2003 clause 2.2.2 schedule J3

6 Forward estimates

(1) A forward estimate is an estimation of the total quantity of electricity that flowed through an ICP during all or part of a consumption period.

(2) A forward estimate may be used only for a period for which an historical estimate cannot be calculated.

(3) The methodology used for calculating a forward estimate may be determined at the discretion of the reconciliation participant, and only if the reconciliation participant ensures that the accuracy of its initial submission information against each subsequent revision cycle submission information for each balancing area is within the percentage of error specified and published, from time to time, by the Authority.

Compare: Electricity Governance Rules 2003 clause 2.2.3 schedule J3
Electricity Industry Participation Code 2010
Schedule 15.3

7 Compulsory meter reading after profile change
(1) If a reconciliation participant changes the profile associated with a meter, it must, when determining the volume information for that meter and its respective ICP, use a validated meter reading or permanent estimate on the day on which the profile change is to take effect.
(2) The reconciliation participant must use the volume information from that validated meter reading or permanent estimate to calculate the relevant historical estimates of each profile for that meter.

Compare: Electricity Governance Rules 2003 clause 2.2.4 schedule J3

8 Provision of submission information to reconciliation manager
(1) For each metering installation for which it is responsible that is category 3 or higher, a reconciliation participant must provide half hour submission information to the reconciliation manager.
(2) For each half-hour metering installation for which it is responsible that is a category 1 metering installation or category 2 metering installation, a reconciliation participant must provide to the reconciliation manager—
   (a) half hour submission information; or
   (b) non half hour submission information; or
   (c) a combination of half hour submission information and non half hour submission information if—
      (i) the half-hour metering installation contains a combination of half-hour metering and non half-hour metering; and
      (ii) clause 2(1)(ae) of this Schedule 15.3 applies.
(3) For each non half-hour metering installation for which it is responsible, a reconciliation participant must provide non half hour submission information to the reconciliation manager.
(4) However, a reconciliation participant need not comply with subclause (2) and subclause (3) if—
   (a) the reconciliation participant is using a profile approved in accordance in Schedule 15.5; and
   (b) the approved profile allows the reconciliation participant to provide half hour submission information from a non half-hour metering installation; and
   (c) the reconciliation participant provides submission information that complies with the requirements set out in the approved profile.
(5) For any unmetered load at an ICP for which it is responsible, regardless of the category of any metering installation at the ICP, a reconciliation participant must provide non half hour submission information to the reconciliation manager unless—
   (a) the Authority has approved a profile for the unmetered load that allows the reconciliation participant to provide half hour submission information to the reconciliation manager for the unmetered load; and
   (b) the reconciliation participant provides half hour submission information in accordance with the profile.
(6) The half hour submission information that a reconciliation participant submits under subclause (1), subclause (2), or subclause (4) must be volume information aggregated to the following levels:
(a) NSP code:
(b) reconciliation type:
(c) profile:
(d) loss category code:
(e) flow direction:
(f) dedicated NSP:
(g) trading period.

(7) The non half hour submission information that a reconciliation participant submits under subclause (2), subclause (3), and subclause (5) must be volume information aggregated to the following levels:
(a) NSP code:
(b) reconciliation type:
(c) profile:
(d) loss category code:
(e) flow direction:
(f) dedicated NSP:
(g) consumption period or day.

Compare: Electricity Governance Rules 2003 clause 3 schedule J3

9 Rounding of submission information
If submission information aggregated by a reconciliation participant under clause 8 is specified to more than 2 decimal places, the reconciliation participant must round the submission information—
(a) to 2 decimal places; and
(b) so that if the digit to the right of the second decimal place is greater than or equal to 5, the second digit is rounded up, and if the digit to the right of the second decimal place is less than 5, the second digit is unchanged.

Compare: Electricity Governance Rules 2003 clause 3A schedule J3

10 Reporting requirements
(1) By 1600 hours on the 13th business day of each reconciliation period, each reconciliation participant must report to the reconciliation manager the proportion of historical estimates per NSP contained within its non half hour submission information.

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

(3) The proportion of submission information per retailer per NSP that is comprised of historical estimates must, unless exceptional circumstances exist, be—
(a) at least 80% for revised data provided at the month 3 revision; and
(b) at least 90% for revised data provided at the month 7 revision; and
Electricity Industry Participation Code 2010
Schedule 15.3

(c) 100% for revised data provided at the month 14 revision.

Compare: Electricity Governance Rules 2003 clause 4 schedule J3

11 Distributed unmetered load database

(1) A retailer must ensure that an up-to-date database is maintained for each type of distributed unmetered load for which it is responsible. The methodology for deriving submission information in the database must comply with Schedule 15.5.

(2) The database must contain at a minimum—

(a) each ICP identifier for which the retailer is responsible, and to which distributed unmetered load is electrically connected; and

(aa) the item or items of distributed unmetered load associated with each ICP identifier; and

(b) the location of each item; and

(c) a description of load type for each item, including any assumptions made in the assessment of its capacity; and

(d) the capacity of each item in watts.

(2A) Each retailer must ensure that each item of distributed unmetered load for which the retailer is responsible is recorded in the database in accordance with this clause.

(3) The database must track the time of additions and changes in a way that enables the total load in kW to be retrospectively derived for any day.

(4) The database must incorporate an audit trail of all additions and changes identifying the before and after values for changes, date and time of the change or addition, and the person making the change or addition.

(5) [Revoked]

Compare: Electricity Governance Rules 2003 clause 5 schedule J3
Clause 11(2A): inserted, on 1 June 2017, by clause 35(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 11(5): revoked, on 1 June 2017, by clause 35(3) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Schedule 15.4
Reconciliation procedures

1 Contents of this Schedule
This Schedule relates to the parts of the reconciliation process performed by the reconciliation manager during each reconciliation period and for relevant consumption periods in accordance with the revision cycle. The following steps comprise the reconciliation process. The requirements of each of these steps are detailed in the remainder of this Schedule. The steps are that the reconciliation manager must—
(a) adjust submission information by ICP days scaling; and
(b) apply loss factors to submission information for half hour metered ICPs that have been adjusted for ICP days; and
(c) profile non half hour submission information into trading periods; and
(d) apply loss factors to submission information for non half hour metered ICPs that have been adjusted for ICP days; and
(e) calculate unaccounted for electricity for each balancing area; and
(f) allocate consumed electricity and unaccounted for electricity to purchasers; and
(g) allocate generated electricity to generators; and
(h) produce reports.

Compare: Electricity Governance Rules 2003 clause 1 schedule J4

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</td>
<td></td>
</tr>
<tr>
<td>Timing</td>
<td>Reconciliation process</td>
<td>Revisions cycles</td>
</tr>
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<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 of the reconciliation period</td>
<td>Each reconciliation participant must seek to resolve all inaccuracies and disputes concerning the reconciliation information.</td>
<td></td>
</tr>
<tr>
<td>By 1600 hours on the 13th business day of the reconciliation period</td>
<td>Each reconciliation participant must submit to the reconciliation manager revised submission information, retailer information and NSP information in accordance with clauses 15.4 to 15.12, 15.27, and 15.28, and clause 10 of Schedule 15.3. The registry manager must make available and the reconciliation manager must procure revised ICP days, loss factor, balancing area and half hour ICP identifiers information, in accordance with clauses 11.24 to 11.27, and clause 10 of Schedule 15.3.</td>
<td></td>
</tr>
</tbody>
</table>
3 Calculation by difference for embedded networks

(1) A trader may by written notice to the reconciliation manager designate an ICP on an embedded network for which the volume information is to be calculated by difference.

(2) A trader must give notice under subclause (1) at least 5 business days before the designation of the ICP takes effect.

(3) Not more than 1 ICP on an embedded network may be designated at any time.

(4) The reconciliation manager must calculate the volume information by trading period for an ICP to which a designation relates using the following formula:

\[ i - x = a \]

where

\( i \) is the loss adjusted quantity of electricity injected into the embedded network derived from NSP and submission information

\( x \) is the loss adjusted quantity of electricity leaving the embedded network derived from NSP and submission information

\( a \) is the differenced volume information for the ICP to which the designation relates.

(5) The reconciliation manager must allocate the volume information calculated under subclause (4) to the ICP to which the designation relates.

(6) A trader may, by written notice to the reconciliation manager, revoke a designation made under subclause (1).

Compare: Electricity Governance Rules 2003 clause 3 schedule J4

4 Calculation by difference for local networks

(1) A trader may apply to the Authority for the Authority to designate part of a local network for which the volume information is to be calculated by difference.

(2) A trader must give notice under subclause (1) at least 10 business days before the date the trader intends the designation to take effect.

Compare: Electricity Governance Rules 2003 clause 2 schedule J4

Clause 2 Rows 2 and 5 of Table: amended, on 5 October 2017, by clause 536 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
(3) The trader must comply with any requirements specified by the reconciliation manager within 5 business days of receiving notice of the requirements.

(4) If the Authority grants a designation, the reconciliation manager must calculate the volume information by trading period for an ICP to which the designation relates using the following formula:

\[ i - x = a \]

where

\[ i \] is the loss adjusted quantity of electricity injected into the local network derived from NSP and submission information

\[ x \] is the loss adjusted quantity of electricity leaving the local network derived from NSP and submission information

\[ a \] is the differenced volume information for the ICP to which the designation relates.

(5) The reconciliation manager must allocate the volume information calculated under subclause (4) to the trader who applied for the designation under subclause (1).

(6) The Authority may revoke the approval of a designation granted under subclause (1).

5 ICP days scaling of submission information excluding embedded generation information

ICP scaling must be used to adjust each retailer’s submission information (excluding embedded generator information) by a factor determined by the number of ICP days submitted for reconciliation compared to the number of ICP days recorded in the registry.

6 ICP days information

(1) Each retailer and each direct purchaser (excluding direct consumers) must deliver to the reconciliation manager, in accordance with clause 15.6, the number of half hour and non half hour ICP days for the NSPs that are recorded in the registry as consuming electricity at any time during the relevant consumption period, upon which the retailer’s or direct purchaser’s submission information is based.

(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.

Compare: Electricity Governance Rules 2003 clause 3A schedule J4

Compare: Electricity Governance Rules 2003 clause 4 schedule J4
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:

\[ \text{ICPSF} = \frac{\text{ICPD\_REG}}{\text{ICPD\_RTL}} \]

where

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICPSF</td>
<td>ICP scaling factor</td>
</tr>
<tr>
<td>ICPD_REG</td>
<td>number of ICP days for that retailer per balancing area as reported by the registry manager</td>
</tr>
<tr>
<td>ICPD_RTL</td>
<td>number of ICP days for that retailer for that balancing area as reported by each retailer</td>
</tr>
</tbody>
</table>

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.

(2) The ICP days scaling factor for direct consumers must be 1.

(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 SI\_ICPD\_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.

(5) The reconciliation manager must, when processing 0 ICP days information, and if data is not supplied, use default values for profile, and loss category code, as determined by the Authority from time to time.

Compare: Electricity Governance Rules 2003 clause 4.2 schedule J4

8 ICP days scaling of submission information (excluding embedded generator information)

(1) The reconciliation manager must separately apply the ICP scaling factors and any additional amount calculated in clause 7 to the reported half hour and non half hour submission information (excluding embedded generator information) of each retailer or direct purchaser (excluding direct consumers) so as to scale up the
submission information in proportion to any under submission by the retailer or direct purchaser.

(2) The ICP scaling factor and any amount calculated in accordance with clause 7 must be applied to the submission information according to the following formula:

\[ SI_{ICPD-ADJ} = (SI \times ICP_{SF}) + SI_{ICPD-ADD} \]

where

- \( SI_{ICPD-ADJ} \) is submission information adjusted for ICP days
- \( SI \) is the amount of electricity reported as part of that retailer’s or direct purchaser’s submission information
- \( ICP_{SF} \) is the ICP scaling factor determined in accordance with clause 7
- \( SI_{ICPD-ADD} \) is the default ICP 0 days volume defined under clause 7(3).

Compare: Electricity Governance Rules 2003 clause 4.3 schedule J4

9 Calculate residual non half hour profile shape
The reconciliation manager must calculate the residual profile shape for each balancing area in accordance with Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 5 schedule J4

Convert non half hour quantities using profiles

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 Authority 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.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J4
Clause 10(a) and (b): amended, on 5 October 2017, by clause 540 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11 Profile shapes or operation logs
If an engineered, statistically sampled or recorded profile forms part of the submission information, the shape file or operation logs associated with the profile must be provided to the reconciliation manager by the reconciliation participant authorised by the profile owner to use that profile for each relevant NSP in respect of the prior consumption period in accordance with clauses 15.4 to 15.12.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J4
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 **Authority** 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.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J4
Clause 12(a) and (b): amended, on 5 October 2017, by clause 541 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 **Authority** for use as a **balancing area** derived **profile** in accordance with Schedule 15.5; and
(b) the **profile owner** has given written notice to the **reconciliation manager** of the approved **profile** code, and that the **profile owner** has authorised the **reconciliation participant** to use the approved **profile** code; and
(c) if the **Authority** has not approved the **profile** code, or submitted the **profile** to the **reconciliation manager** in accordance with clause 12(1) of Appendix 1 of Schedule 15.5, the **reconciliation manager** must use the final residual **profile** shape as defined in Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J4
Clause 13(a) and (b): amended, on 5 October 2017, by clause 542(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 13(c): replaced, on 5 October 2017, by clause 542(c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

14 Invalid submission information
If invalid **submission information** is submitted, and the **reconciliation manager** cannot obtain corrected information within a reasonable time period from the **reconciliation participant**, the **reconciliation manager** must—
(a) use the default values specified in this Code (if any); or
(b) if the default values described in paragraph (a) do not exist, use the default values specified by the **Authority** (if any); or
(c) if the default values described in paragraph (b) do not exist, temporarily replace the invalid data with an estimate.

Compare: Electricity Governance Rules 2003 clause 6.5 schedule J4
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).
(2) If the Authority makes such a direction, the reconciliation manager must, after adjustment for ICP days scaling and the application of profiles, apply such loss factors to all submission information for all reconciliation periods during which the Authority’s direction is current.

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

- \( UFE_{BA} \) is the unaccounted for electricity for each balancing area for the relevant trading period.
- \( TOT_{BA} \) 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.
- \( Q_{BA-EN} \) is all electricity conveyed to consumers 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

- \( UFE\text{Factor}_{BA} \) is the unaccounted for electricity factor in respect of each balancing area for each trading period.
Q_{ICPD-LA} is all electricity conveyed to consumers and embedded networks connected to the balancing area, being the sum of the consumption parts of submission information, adjusted for losses and ICP days.

TOT_{BA} has the meaning given to it in subclause (1).

17 Scorecard rating

(1) The reconciliation manager must rate each retailer relative to all other retailers using a scorecard rating. The numerical scores must be determined in accordance with this clause and clause 18 and used to weight the portion of unaccounted for electricity to be allocated to each retailer.

(2) Each retailer must provide to the reconciliation manager, in accordance with clause 15.7, the quantity of electricity supplied.

(3) The reconciliation manager must allocate electricity supplied quantities, to reconciliation periods for reporting and calculation purposes and in the event of unusual circumstances that must have been approved beforehand in writing by the Authority, re-allocate quantities on a reasonable basis to reflect the month(s) of actual usage.

18 Calculation of scorecard rating

(1) The reconciliation manager must calculate, publish and apply the scorecard rating for each retailer as follows:

(a) the scorecard rating for each retailer must be calculated and published by the reconciliation manager in respect of each reconciliation period from which the reconciliation manager processes submission information, but must only be applied in respect of the 7 and 14 month revisions;

(b) the scorecard rating for each retailer for each balancing area (SC_{Ri}) must, subject to subclause (4), be calculated according to the following formula (provided that if the scorecard rating is calculated through the application of the formula to be less than 1, then SC_{Ri} is set to 1):

\[ SC_{Ri} = \frac{AES_{Ri}}{(ACI_{Ri} \times SC_{Thres})} \]

where
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Schedule 15.4

SC<sub>Ri</sub> is the scorecard rating and the subscript “Ri” is a retailer, for each consumption period and each balancing area

AES<sub>Ri</sub> is the sum of the electricity supplied quantities for the 12 months up to and including the month of the relevant consumption period

ACI<sub>Ri</sub> is the sum of the submission information quantities (ICP days adjusted but non loss adjusted) for the 12 months up to and including the month before the relevant consumption period

SC<sub>Thres</sub> is the scorecard threshold (that allows for a degree of expected misalignment between the annualised electricity supplied and submission information quantities) and has the value specified by the Authority from time to time:

(c) in all cases, the latest electricity supplied and submission information quantities submitted to the reconciliation manager by the retailer must be used.

(2) The scorecard rating for each retailer must be set to 1.25 if the retailer has not provided the reconciliation manager with any of the required information.

(3) Despite subclauses (1) and (2), the scorecard rating for direct consumers and direct purchasers must be 1.

(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 participants that the scorecard rating will be calculated and applied in accordance with this clause.

Compare: Electricity Governance Rules 2003 clauses 9.2 and 9.3 schedule J4

19 Calculation of unaccounted for electricity
The reconciliation manager must apportion unaccounted for electricity to each retailer and direct purchaser at each NSP and for each trading period using the following formulae:

\[
UF_{ER_i} = UF_{EA} \times AF_{Ri}
\]

\[
AF_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{\sum(SC_{R1} \times MS_{R1}, ..., SC_{Rn} \times MS_{Rn})}
\]

\[
MS_{Ri} = \frac{Q_{ICPD-LA \ R_i}}{\sum(Q_{ICPD-LA \ 1}, ..., Q_{ICPD-LA \ n})}
\]

where, for each trading period

UF<sub>ERi</sub> is the quantity of unaccounted for electricity to be allocated to each retailer or direct purchaser

UF<sub>EA</sub> is the quantity of unaccounted for electricity for each balancing area calculated by the reconciliation manager in accordance with clause 16(1)
$Q_{ICPD-LA Ri}$ is the quantity of electricity attributed to each retailer or direct purchaser, which has been adjusted for losses and ICP days at each NSP, determined by the reconciliation manager from that retailer’s or direct purchaser’s submission information.

$AF_{Ri}$ is the unaccounted for electricity allocation factor, expressed as a fractional number (not less than 0 or greater than 1), for each retailer or direct purchaser at each NSP, determined by the reconciliation manager.

$MS_{Ri}$ is the market share proportion, expressed as a fractional number (not less than 0 or greater than 1), for each retailer or direct purchaser at each NSP to be determined by the reconciliation manager from all submission information at that NSP.

and, for each consumption period

$SC_{Ri}$ is the scorecard rating for each retailer or direct purchaser for each balancing area determined by the reconciliation manager in accordance with clauses 17 and 18.

Compare: Electricity Governance Rules 2003 clause 10.1 schedule J4

### 20 Allocation of unaccounted for electricity

The reconciliation manager must add each retailer’s or direct purchaser’s share of unaccounted for electricity to the previously calculated ICP days and loss adjusted submission information at each NSP for each trading period using the following formula:

$$Q_{ILU Ri} = Q_{ICPD-LA Ri} + UFE_{Ri}$$

where, for each trading period

$Q_{ILU Ri}$ is the quantity of electricity to be attributed to each retailer or direct purchaser that has been ICP days scaled, and loss adjusted and is UFE inclusive.

$Q_{ICPD-LA Ri}$ and $UFE_{Ri}$ have the meaning given to them in clause 19.

Compare: Electricity Governance Rules 2003 clause 10.2 schedule J4

### 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).

Compare: Electricity Governance Rules 2003 clause 11 schedule J4

22 **Balancing**

The **reconciliation manager** must balance the **UFE inclusive, ICP days** and loss adjusted **submission information** so that the sum of each **reconciliation participant**’s quantities equals each **NSP** metered quantity during each **trading period**. The following process must be used by the **reconciliation manager**:

(a) for each **retailer** or **direct purchaser**, at each **NSP**, any quantities that have been designated as being attributable to a specific **NSP** within the **balancing area** must be separated off from the remaining non-dedicated quantity and remain allocated to the specific **NSP**. If the sum of each **retailer**’s dedicated-**NSP** quantities exceeds the amount of **electricity** conveyed at the **NSP** in any **trading period**, the **NSP** total must be apportioned to the relevant **retailers** or **direct purchasers** in proportion to their dedicated-**NSP** quantities. The net quantities of non-dedicated **electricity** at each **NSP** must be determined by subtracting the dedicated quantities from the **NSP** totals:

(b) the **NSPs** within a **balancing area** that have been over-allocated **electricity** must be identified by comparing the sum of the non-dedicated quantities for each **retailer** and **direct purchaser** with the net **NSP** quantity. The non-dedicated quantities for each **retailer** and **direct purchaser** at each over-allocated **NSP** must be adjusted in order to achieve balance as follows:

\[
Q_{\text{BAL NSP}_x R_i} = \frac{Q_{\text{ILUN NSP}_x R_i} \times TOT_{\text{ND NSP}_x}}{\text{sum}(Q_{\text{ILUN NSP}_x R_1}, \ldots, Q_{\text{ILUN NSP}_x R_n})}
\]

where

- \(Q_{\text{BAL NSP}_x R_i}\) is the quantity of fully adjusted, non dedicated **electricity** per **NSP** allocated to each **retailer** and **direct purchaser** after balancing to match the **NSP** total
- \(Q_{\text{ILUN NSP}_x R_i}\) is the quantity of non-dedicated **electricity** per **NSP** attributed to each **retailer** and **direct purchaser**, which has been adjusted for **losses** and **ICP days**, and is **UFE inclusive**
- \(TOT_{\text{ND NSP}_x}\) is the quantity of non-dedicated **electricity** conveyed at the **NSP** (after allowing for relevant **balancing area** injection and extraction quantities):

(c) the **reconciliation manager** must identify the quantities of **electricity** by which the over-allocated **NSPs** have been reduced, by **retailer** and by **direct purchaser**, and re-allocate to the corresponding under-allocated **NSPs** within the **balancing area** using the following formulae:

(i) calculate the previously over-allocated quantity per **retailer** and **direct purchaser** per **balancing area** as follows:
\[ Q_{\text{OVER Ri}} = \text{sum}(Q_{\text{ILUN NSP1 Ri}} - Q_{\text{BAL NSP1 Ri}}, \ldots, Q_{\text{ILUN NSPn Ri}} - Q_{\text{BAL NSPn Ri}}) \]

where

\[ Q_{\text{OVER Ri}} \]

is the sum, over all NSPs in the balancing area that are over-allocated per retailer and direct purchaser, of the differences between the pre- and post-adjusted quantities in paragraph (b); and

\[ Q_{\text{ILUN NSP1 Ri}} \text{ and } Q_{\text{BAL NSP1 Ri}} \]

have the meaning given to them in paragraph (b):

(ii) determine the proportions by which the over-allocated quantity must be allocated to the under-allocated NSPs, per retailer and direct purchaser, in order to ensure that the sum of all reconciliation participants’ totals balance, after re-allocation, to the NSP totals as follows:

\[ \text{PR}_{\text{NSPx}} = \frac{(\text{TOT}_{\text{ND NSPx}} - \text{sum}(Q_{\text{ILUN NSPx R1}} \ldots Q_{\text{ILUN NSPx Rn}}))}{Q_{\text{OVER BA}}} \]

where

\[ \text{PR}_{\text{NSPx}} \]

is the proportion by which the over-allocated quantity must be allocated to the under-allocated NSPs, per retailer and direct purchaser

\[ Q_{\text{OVER BA}} \]

is the sum of all over-allocated quantities for all retailers and direct purchasers for all over-allocated NSPs in the relevant balancing area

\[ \text{TOT}_{\text{ND NSPx}} \text{ and } Q_{\text{ILUN NSPx R1}} \]

have the meaning given to them in paragraph (b):

(iii) allocate the over-allocated quantities to each retailer and direct purchaser at each under-allocated NSP as follows:

\[ Q_{\text{BAL NSPx Ri}} = Q_{\text{OVER Ri}} \times \text{PR}_{\text{NSPx}} + Q_{\text{ILUN NSPx Ri}} \]

where

\[ Q_{\text{BAL NSPx Ri}} \]

is the over-allocated quantities of electricity attributed to each retailer and direct purchaser at each under-allocated NSP;

\[ Q_{\text{OVER Ri}} \]

has the meaning given to it in subparagraph (i)

\[ Q_{\text{ILUN NSPx Ri}} \]

has the meaning given to it in paragraph (b); and

\[ \text{PR}_{\text{NSPx}} \]

has the meaning given to it in subparagraph (ii).
23 Final quantities
The reconciliation manager must determine the final quantities of electricity to be purchased by each reconciliation participant by adding the dedicated and non-dedicated, balanced quantities using the following formula:

\[ Q_{TOT \text{ Ri}} = Q_{BAL \text{ NSPx Ri}} + Q_{DED \text{ Ri}} \]

where

- \( Q_{TOT \text{ Ri}} \) is the final quantity of electricity to be purchased by each reconciliation participant determined by adding the dedicated and non-dedicated balanced quantities
- \( Q_{BAL \text{ NSPx Ri}} \) has the meaning given to it in clause 22(c)(iii)
- \( Q_{DED \text{ Ri}} \) are the quantities of electricity to be purchased by each reconciliation participant for dedicated quantities.

24 Reconciliation manager reporting requirements
The reconciliation manager must provide the information specified in clauses 25 to 27 to those reconciliation participants, participants and the Authority listed in those clauses, in respect of the prior consumption period, by 1600 hours on the 7th business day of each reconciliation period, and in respect of revisions in accordance with clauses 15.27 and 15.28 by 1200 hours on the last business day of each reconciliation period.

25 Retailer and direct purchaser reports
The reconciliation manager must make the following reports available to each relevant retailer and direct purchaser trading on the network:

(a) the reconciliation manager must produce 3 reports of the UFE factors for each NSP per retailer and direct purchaser, being—
   (i) 1 report by trading period; and
   (ii) 1 report by consumption period; and
   (iii) 1 report issued monthly in respect of the immediately preceding 12 consumption periods:

(b) the reconciliation manager must report to each retailer and direct purchaser the retailer’s and direct purchaser’s own scorecard and market share proportions for each NSP:

(c) the reconciliation manager must report the non half hour and half hour ICP days scaling factor for each NSP and each retailer and direct purchaser:
(d) the reconciliation manager must report to each retailer and direct purchaser the retailer’s and direct purchaser’s monthly totals for half hour metered ICPs as supplied by that retailer and direct purchaser in accordance with clause 15.8, for which submission information has not been received within the time required by this Code:

(e) the reconciliation manager must report to each retailer and direct purchaser the retailer’s and direct purchaser’s number of ICP days for which submission information has not been received within the time required by this Code, separately for non half hour and half hour meter types:

(f) the reconciliation manager must report all half hourly metered ICPs that have switched retailer and direct purchaser in the previous 2 months and for which consumption has changed by a percentage determined by the Authority.

Compare: Electricity Governance Rules 2003 clause 14.1 schedule J4

26 Distributor reports
The reconciliation manager must forward a report to each distributor that includes the following information:

(a) electricity traded for each trader trading on the distributor’s network:

(b) electricity supplied information for each trader trading on the distributor’s network:

(c) submission information for each trader trading on the distributor’s network.

Compare: Electricity Governance Rules 2003 clause 14.2 schedule J4

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 unaccounted 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.

Compare: Electricity Governance Rules 2003 clause 14.3 schedule J4
Clause 27(c): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

28 Provision of reconciliation information
The reconciliation manager must provide the following information to the clearing manager and those participants listed below, and in the case of paragraph (f), to the Authority, in respect of the prior consumption period, by 1600 hours on the 7th business day of each reconciliation period, and in respect of revisions in accordance with clauses 15.27 and 15.28 by 1200 hours on the last business day of each reconciliation period. These reports must be in the format, and contain the information determined by the Authority. The reports are—
(a) to each generator or purchaser, the reconciliation information applying to that generator or purchaser, to enable the generator or purchaser to verify its reconciliation information; and
(b) to each grid owner, such information as is required by that grid owner to calculate its charges; and
(c) to the clearing manager, the reconciliation information (including all amounts derived by the reconciliation manager in accordance with clause 20) applying to each participant to enable the clearing manager to calculate the amounts owing by the clearing manager to each participant and by each participant to the clearing manager; and
(d) to each retailer and direct purchaser, the calculated daily seasonal adjustment shape related to any point of connection for which the retailer and direct purchaser is trading; and
(e) to each retailer, generator, and direct purchaser, the reconciliation manager must publish half hour profile shape data for profiles; and
(f) to the Authority, the reconciliation manager must provide the report prepared by the reconciliation manager referred to in clause 10 of Schedule 15.3; and
(g) to the extended reserve manager, the reconciliation information applying to each participant to enable the extended reserve manager to carry out and manage its procurement process.

Clause 28(g): inserted, on 19 January 2017, by clause 17(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.

29 Extended reserve manager use of reconciliation information
The extended reserve manager must not publish or otherwise make available any reconciliation information provided to it under clause 28 that identifies any retailer, purchaser, or generator.
1 Contents of this Schedule
This Schedule (including the appendices) contains the requirements for the production of profiles that must be used for electricity trading if a metering installation or unmetered load meets the eligibility criteria described in this Schedule.

Compare: Electricity Governance Rules 2003 clause 1 schedule J5

2 Departure from requirements
The 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.

Compare: Electricity Governance Rules 2003 clause 2 schedule J5

3 Load switching
If load switching information is required from the operation log of an external control system, such as a SCADA or ripple injection control system, the relevant reconciliation participant must ensure that the information, for the immediately preceding consumption period, is available by 1600 hours on the 4th business day of each month.

Compare: Electricity Governance Rules 2003 clause 3.1 schedule J5

4 Non metering information
A reconciliation participant using a profile must ensure that all non-metering information, such as external control equipment operation logs, used in the determination of profile data, is archived in accordance with clause 18 of Schedule 15.2.

Compare: Electricity Governance Rules 2003 clause 3.2 schedule J5

5 Profile population
Each reconciliation participant who uses a profile must keep a current profile population list for each month the profile is in use. This will form a part of the audit trail of how profiles are applied.

Compare: Electricity Governance Rules 2003 clause 3.3 schedule J5

6 Details of profile approved for use
(1) Each profile owner must keep a full copy of all of the details of each profile approved for use.

(2) The details must be kept in accordance with clause 18 of Schedule 15.2 for audit purposes.

Compare: Electricity Governance Rules 2003 clause 3.4 schedule J5

7 Multiple meter registers
If a metering installation has multiple meters or meters with multiple registers, a reconciliation participant may choose to have each meter or meter register treated as 1 of the profiles described in Appendix 1.

Compare: Electricity Governance Rules 2003 clause 3.5 schedule J5

8 New profiles
Each new profile must be developed in accordance with this Schedule.

Compare: Electricity Governance Rules 2003 clause 3.6 schedule J5

9 Accuracy of clocks
External or internal clocks used for switching of meter registers must have a time-keeping accuracy of better than 60 seconds per month. The current time indicated by each clock must be checked for accuracy at least once per year, and corrected as necessary.

Compare: Electricity Governance Rules 2003 clause 3.7 schedule J5

10 Subtractive metering
If a metering installation includes subtractive metering, each participant must derive the appropriate net consumptions.

Compare: Electricity Governance Rules 2003 clause 3.8 schedule J5

11 Change of profile
(1) A profile owner may apply to the 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 Authority must not approve an application unless the 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 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.

Compare: Electricity Governance Rules 2003 clause 3A schedule J5

12 Approved profile classes
(1) Approved profile classes are described in Appendix 1.
(2) Each reconciliation participant must, with the exception of profile classes 1.4 and 1.5, apply to use specific profiles within those profile classes in accordance with clauses 19 to 34.

Compare: Electricity Governance Rules 2003 clause 4 schedule J5
13 Allocation and storage of profile codes

(1) The Authority must determine the profile code for an approved profile in accordance with this clause.

(2) Profile class 1.4 and 1.5 each have a single approved profile code, being—
   (a) the profile code for the single approved profile in profile class 1.4 is RPS; and
   (b) the profile code for the single approved profile in profile class 1.5 is UML.

(3) Profile class 2.5 has 2 approved profile codes, being—
   (a) the profile code for the approved profile in profile class 2.5.1 non half hour photovoltaic embedded generation, is PV1; and
   (b) the profile code for the approved profile in profile class 2.5.2 other non half hour embedded generation, is EG1.

(4) Profile class 1.7 has a single approved profile being, for differenced load, DFP.

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

   profile reference: the unique reference under which the profile is allocated and stored
   profile class: refer to Appendix 1
   characteristics: type(s) of meter(s): A – None
   type(s) of load(s) D – Controlled
   description: a brief description of the type of consumer or embedded generator to whom the profile applies.

Compare: Electricity Governance Rules 2003 clause 5 schedule J5

14 Calculate residual non half hour profile shapes

The reconciliation manager must calculate, half hour by half hour, a residual profile shape for each balancing area that must be used to allocate non half hour submission information (after adjustment for losses and ICP days) to trading periods in accordance with clauses 15 to 18.

Compare: Electricity Governance Rules 2003 clause 6 schedule J5

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.

(2) The process in subclause (1) must be carried out for each trading period and for each balancing area within which there is non half hour metered electricity to be reconciled by following the procedure below:
TOT_{BA} = (E_{GD} + E_{LN} + E_{EN}) - (L_{GD} + L_{LN} + L_{EN}) + (E_{EG})

where

TOT_{BA} 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 balancing area, as measured by the grid NSP metering installation for the balancing area.

E_{LN} is the quantity of electricity, entering the balancing area through an interconnection point from another network, as measured by the NSP metering installation (which has been adjusted for losses).

L_{GD} is the quantity of electricity leaving the balancing area, as measured by the grid NSP metering installation for the balancing area.

E_{EN} is the quantity of electricity entering the balancing area from an embedded network, as measured by the NSP gateway metering installation for the embedded network.

E_{EG} is the quantity of electricity entering the balancing area from an embedded generator electrically connected to the network, (which may either be half hour or non half hour metered), as measured by the NSP metering installation.

L_{LN} is the quantity of electricity, leaving the balancing area through an interconnection point to another network, as measured by the NSP metering installation (which has been adjusted for losses).

L_{EN} is the quantity of electricity, leaving the balancing area to an embedded network, as measured by the NSP gateway metering installation for the embedded network.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J5

16 Calculate total non half hour shape
(1) Using the total balancing area quantities determined in accordance with clause 15 and the reconciliation participants’ half hour submission information (that has been
adjusted for losses and ICP days), the reconciliation manager must calculate, for each trading period, a total profile shape representing the aggregated consumption of all non half hour metered electricity for each balancing area by following the procedure below:

\[ \text{NHH}_{\text{Tot}} = \text{TOT}_{\text{BA}} - \text{HHR}_{\text{M}} \]

where

- \( \text{NHH}_{\text{Tot}} \) is the total quantity of non half hour metered electricity consumed in a balancing area provided that if the calculated quantity is less than 0, the quantity must, for the purposes of this clause, be deemed to be 0
- \( \text{TOT}_{\text{BA}} \) is the total quantity of electricity consumed within the balancing area, determined in accordance with clause 15
- \( \text{HHR}_{\text{M}} \) is the total quantity of consumed electricity which is calculated from all reconciliation participants’ half hour submission information (which has been adjusted for losses and ICP days).

(2) The volumes described in subclause (1) must not be published and are a process step only.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J5

17 Calculate initial residual profile shape and seasonal adjustment shape

(1) Using the resultant \( \text{NHH}_{\text{Tot}} \) quantities from the calculation in clause 16, the reconciliation manager must calculate, for each trading period, half hour by half hour, the initial residual profile shape for each balancing area by following the procedure below:
Electricity Industry Participation Code 2010
Schedule 15.5

\[ \text{GXP}_{\text{Init}} = \text{NHH}_{\text{Tot}} - (\text{Pr}^{\text{ENG}} + \text{Pr}^{\text{STAT}}) \]

Sum of independently shaped, non half hour profiled consumption internal to the network area

where

- \( \text{GXP}_{\text{Init}} \) is the Initial Residual Profile. This is the remaining total quantity of electricity for each half hour that represents the shape-dependent balance of the non half hour consumption within a balancing area. This set of values, calculated for each trading period, is the initial residual profile for each NSP within the balancing area.

- \( \text{NHH}_{\text{Tot}} \) is as determined in clause 16.

- \( \text{Pr}^{\text{ENG}} \) is the quantity of consumed electricity for each trading period that is in accordance with the approved engineered profile, calculated from the reconciliation participant submission information adjusted for ICP days and after application of loss factors.

- \( \text{Pr}^{\text{STAT}} \) is the quantity of consumed electricity for each trading period that is in accordance with the approved statistically sampled profile, calculated from the reconciliation participant submission information adjusted for ICP days and after the application of loss factors.

(2) The \( \text{GXP}_{\text{Init}} \) values must be used by the reconciliation manager to allocate non half hour submission information to trading periods for each reconciliation participant that uses a profile that specifies the use of the initial residual profile shape at the NSP.

(3) The reconciliation manager must aggregate those trading period volumes into daily totals for each profile at the NSP, and those daily totals must be published by the reconciliation manager as the seasonal adjustment shape.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J5

18 Calculate final residual profile shape

(1) Using the resultant \( \text{GXP}_{\text{Init}} \) quantity from the calculation in clause 17, the reconciliation manager must calculate, for each trading period, the final residual profile shape for each balancing area by following the procedure below:
Electricity Industry Participation Code 2010
Schedule 15.5

\[ GXP_{\text{Res}} = GXP_{\text{Init}} - (\text{PrSh}_1 + \ldots + \text{PrSh}_n) \]

where

- GXP_{\text{Res}} is the Final Residual Profile (which is given the code “RPS”). This is the remaining quantity of electricity for each trading period that represents the shape dependent balance of the non half hour load within a balancing area. The monthly file of this consumption, calculated for each trading period, is the final residual profile for each NSP within the balancing area.
- GXP_{\text{Init}} is as determined in clause 17.
- PrSh_X is the quantity of consumed electricity for each trading period which is in accordance with the approved shape dependent profile calculated from the reconciliation participant loss and ICP days adjusted submission information.

(2) The GXP_{\text{Res}} values in subclause (1) must be used by the reconciliation manager to allocate non half hour submission information to trading periods for each reconciliation participant who uses a profile that specifies the use of the residual half hour shape at the NSP, for each trading period of the reconciliation period.

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J5

New NSP derived profiles

19 Applications

(1) An application to introduce a new NSP derived profile must be submitted to the 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.

(2) Each application must contain the following—
   (a) a profile description;
   (b) a suggested profile code;
   (c) a profile class in accordance with Appendix 1;
   (d) the criteria applied by the profile applicant to allocate ICP identifiers in the profile;
   (e) a description of the methodology for compiling submission information and profile shapes:
(f) details of dynamics derived from sources external to the metering installation (including without limitation SCADA and ripple control) if appropriate.

Compare: Electricity Governance Rules 2003 clause 7.1 schedule J5

20 Assessment

Before approving a profile, the Authority must be satisfied that—
(a) there are clear criteria applied by the reconciliation participant to allocate ICP identifiers in the profile; and
(b) there are no obvious flaws in the methodology for compiling submission information and profile shapes; and
(c) the reconciliation manager is able to incorporate the profile into the reconciliation process; and
(d) the proposed profile is not at variance with existing profiles for like populations.

Compare: Electricity Governance Rules 2003 clause 7.2 schedule J5

21 Ownership

For the purposes of this Schedule, a profile applicant must become the profile owner once the application is approved. If the profile applicant is not a legal entity, a legal entity must be nominated by the profile applicant to be the profile owner.

Compare: Electricity Governance Rules 2003 clause 7.3 schedule J5

22 Withdrawal of applications

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

Compare: Electricity Governance Rules 2003 clause 7.4 schedule J5

23 Rejected applications

If an application is rejected, the 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.

Compare: Electricity Governance Rules 2003 clause 7.5 schedule J5

24 Use of approved profiles

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

(2) A reconciliation participant who wishes to reconcile its ICP identifiers using an existing profile must first gain the approval of the profile owner.

Compare: Electricity Governance Rules 2003 clause 7.6 schedule J5
25 Technical requirements
A new profile must be based on a process of statistical sampling carried out in accordance with the guidelines contained in the appendices to this Schedule, or derived using recognised engineering principles, or derived from NSP profiles.

26 Applications
(1) An application to introduce a new profile must be submitted to the 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. Each application must contain the following:
   (a) a profile description:
   (b) a suggested profile code:
   (c) a profile class in accordance with Appendix 1:
   (d) the size of the profile population and a list that uniquely identifies each member of the profile population:
   (e) the criteria applied by the reconciliation participant to allocate ICP identifiers to the profile:
   (f) a description of the methodology for compiling submission information and profile shapes:
   (g) details of dynamics derived from sources external to the metering installation (including without limitation SCADA and ripple control) if appropriate:
   (h) details of any half-hour metering as a control or source of input data to the profile:
   (i) statistical or engineering data that supports the proposed profile shape.

27 Assessment
The Authority must be satisfied that—
   (a) there are clear criteria applied by the reconciliation participant to allocate profiles to ICP identifiers; and
   (b) there is an audit trail for the allocation of profiles to ICP identifiers; and
   (c) there are no obvious flaws in the methodology for allocating profiles to ICP identifiers; and
   (d) the reconciliation manager is able to incorporate the profile into the reconciliation process; and
   (e) the proposed profile is not at variance with existing profiles for like populations.
28 Sampling requirements

(1) Statistical samples must be drawn using the methodology described in Appendix 2. Sampling information must be taken from fully certified metering installations. An interim certified metering installation must not be used for this purpose.

(2) For profiles that require statistical sampling, the 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 Authority must require a minimum sampling period of 60 days, and not more than 12 months. The 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 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 Authority can reject the application, or can require the profile applicant to supply additional information until the 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 Authority must draw an additional random sample. The size of the additional random sample must equal the shortfall.

(6) If the profile sample size is less than the preliminary sample size, the preliminary sample must become the profile sample.

29 Ownership

For the purposes of this Schedule, a profile applicant must become the profile owner once the application is approved. If the profile applicant is not a legal entity, a legal entity must be nominated to be the profile owner.

30 Withdrawal of applications

If an application is withdrawn by a profile applicant at any time following the declaration date, but before approval, the Authority must advise all participants.
31 Rejected applications

(1) If an application is rejected, the 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.

(2) If an application is rejected because the coefficient of variation is found to be too large, the profile applicant may resubmit the application with a refined profile population.

(3) The refined profile population must be a subset of the original population and must be made up of ICP identifiers that are more homogenous in their unit costs than those in the original profile population.

(4) Data collected from half-hour metering in the original preliminary sample may be reused to constitute the refined preliminary sample as long as the data was collected from ICP identifiers that belong to the refined profile population.

(5) The 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 Authority approves it. The use of a profile must be effective from a date decided by the 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.

(2) A reconciliation participant who wishes to reconcile its eligible ICP identifiers using an existing profile must first gain the approval of the profile owner. ICP identifiers not already on the profile population list must be added to the list before the profile can be applied.

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 Authority when an update is necessary (refer subclause (3)). The profile population list is subject to random audit by the 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, give written notice to the Authority of the changes in the profile population list. The Authority must determine, and give written notice to the profile owner of, any required modifications to the profile sample. The profile owner has 1 month from the date on which the profile owner receives the notice from the 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 Authority a list of ICP identifiers in the current profile sample who have been lost or removed from the profile population list. The 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 Authority 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.

Compare: Electricity Governance Rules 2003 clauses 8.9.1 and 8.9.2 schedule J5

34 Exceptions to sampling methodology
The Authority may allow different sampling methodologies that are not described in this Schedule, only if—

(a) the methodology can, in the Authority’s assessment, produce sample data that meets the precision standards specified under Appendix 2; and

(b) the 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

(c) following the declaration date but before approval, details of the shape of the proposed profile must be provided by the profile owner on a monthly basis to all participants trading on the affected NSP(s). Use of such profile information is subject to clause 32. Following approval, such details must be provided to all participants by the reconciliation manager.

Compare: Electricity Governance Rules 2003 clause 8.9.3 schedule J5

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 Authority or its agent must audit the application of all profiles in a random order at least once every 2 years by applying a selection process that the Authority determines.

(3) As a minimum, a profile audit must cover the following:

(a) the documents detailing the methodology of the profile:
(b) the application of dynamic and estimated elements of the profile:
(c) the profile population list.

Compare: Electricity Governance Rules 2003 clause 9 schedule J5

36 Reviews
(1) The 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.

Compare: Electricity Governance Rules 2003 clause 10 schedule J5

37 Removal of profiles
(1) The Authority must immediately remove a profile that fails an audit from the list of approved profiles held by the Authority.

(2) A participant who includes in a profile an ICP identifier that is not of the classification contained in the profile documentation breaches this Code. All alleged breaches must be reported to the Authority and resolved in accordance with the Act.

(3) The Authority may remove a profile—
(a) at the request of the profile owner that introduced the profile; or
(b) for such other reasons that the Authority decides.

(4) A profile owner that makes a request to the Authority under subclause (3)(a) must—
(a) make the request in writing; and
(b) request the profile's removal be effective from the start of the reconciliation period immediately following the date on which the Authority receives the request.

(5) If the Authority removes a profile, the Authority must decide on the actions to be taken with respect to the ICP identifiers to which the profile applied.

Compare: Electricity Governance Rules 2003 clause 11 schedule J5
Clause 37(3) to (5): replaced, on 5 October 2017, by clause 567(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Appendix 1
Profile classes

1 Contents of this Appendix
This Appendix contains generic descriptions of metering installations to which particular profile classes may be assigned.
Compare: Electricity Governance Rules 2003 appendix 1 schedule J5

Participants NSP-derived profiles

2 Profile class 1.1 interval time of use meters
(1) Meters in the profile class 1.1 – interval time of use meter classification include the following:
   (a) day-night two rate meters;
   (b) night only meters;
   (c) night only plus afternoon boost meters;
   (d) 5 rate time of use meters.
(2) If register-switching is triggered by an external signal, such as a ripple relay, rather than by the meter’s internal clock, data from the operation log of the equipment controlling the external signal must be used to provide the profile time period.
Compare: Electricity Governance Rules 2003 clause 1.1 appendix 1 schedule J5

3 Profile class 1.2 separately metered controlled load
(1) Meters in the profile class 1.2 separately metered controlled load classification include a separate 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 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 meters in the metering installation must be applied as per profile class 1.1 or 1.4, as appropriate.
Compare: Electricity Governance Rules 2003 clause 1.2 appendix 1 schedule J5

4 Profile class 1.3 non separately metered controlled load
(1) Installations in the profile class 1.3 classification non separately metered controlled load include a ripple controlled water heater but with only 1 meter measuring the whole installation including the water heater.
(2) The controlled load may be switched on and off at variable times of the day. In this case a proportion of the profile (kWh) must be applied as per profile class 1.2 with the remaining kWh applied as per profile class 1.1 or 1.4, as appropriate.

Compare: Electricity Governance Rules 2003 clause 1.3 appendix 1 schedule J5

5 Profile class 1.4 uncontrolled load 24 hour meters
(1) The profile from meters in the profile class 1.4 uncontrolled load 24 hour meters must follow the NSP residual profile.
(2) The NSP residual profile must be calculated in accordance with clauses 14 to 18 of Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 1.4 appendix 1 schedule J5

6 Profile class 1.5 unmetered loads
(1) Unmetered loads in the profile class 1.5 classification include, but are not limited to, under veranda lighting, electric fences, sewer pumps, advertising hoardings, public conveniences, supply to construction sites, electric parking meters, and public water fountains.
(2) For those types of unmetered load, a fixed annual kWh quantity must be assigned to each ICP and must be applied according to the 24 hour NSP final residual profile.

Compare: Electricity Governance Rules 2003 clause 1.5 appendix 1 schedule J5

7 Profile class 1.7 differenced load
Profile class 1.7 differenced load represents the result of subtractive processes performed by the reconciliation manager to form differenced load.

Compare: Electricity Governance Rules 2003 clause 1.7 appendix 1 schedule J5

8 Profile class 2.1 unmetered loads
(1) Profiles may be applied to intended loads with characteristics that are reasonably predictable using time and other observable values.
(2) The elements making up each load and time period must be documented by the profile owner.
(3) The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

Compare: Electricity Governance Rules 2003 clause 2.1 appendix 1 schedule J5

9 Profile class 2.2 half hour data, metering installations with interim certification
(1) Half hour data from interim certified metering installations may be—
   (a) regarded as a 100% sampled profile until the expiry of the interim exemption validity period for those metering installations under Part 10. From that date, if the metering installation has not been recertified as a fully certified metering installation under Part 10, the metering installation must be assigned to profile class 1.4; or
(b) treated as if it was derived from fully certified metering installations until the expiry of the interim exemption validity period for those metering installations. To avoid doubt, the half hour data must be derived from an interrogation of the metering installation and must be submitted to the reconciliation manager in accordance with Schedule 15.4.

(2) For a 100% sampled profile, a method of calculating forward estimates must be adopted in accordance with clauses 2 to 7 of Schedule 15.3. A profile shape for the reconciliation period must be submitted to the reconciliation manager with the estimated data.

(3) If the gathering, validation and repair of volume information from an interim certified metering installation is carried out in a manner that is not in accordance with Schedule 15.2, these processes must be fully documented in the quality procedures of the participant.

10 Profile class 2.3 unmetered installations that require shape file to be submitted

(1) A profile may be applied to an intended load with characteristics that are reasonably predictable using time and other observable values.

(2) For those types of unmetered load, the profile must include a process for maintaining unmetered load quantities that are used in the reconciliation process. The shape file will be produced by the profile owner from a metering installation.

(3) The elements making up each load and time period must be documented by the profile owner. The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

11 Profile class 2.4 metered installations that require shape file

(1) A profile may be applied to an intended load with characteristics that are reasonably predictable using time and other observable values.

(2) For those types of metered load, a metering installation must be used to determine the quantity of electricity for reconciliation purposes.

(3) The elements making up each load and time period must be documented by the profile owner. The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

12 Profile class 2.5, non half hour embedded generation

(1) The Authority must—

(a) determine how each of the 2 types of non half hour embedded generator profiles under subclause (2) applies and operates; and
(b) having made its determination under paragraph (a), submit each non half hour embedded generator profile to the reconciliation manager.

(2) The 2 types of non half hour embedded generator profiles are:

(a) the photovoltaic is a time limited profile and may only be used for photovoltaic generation that injects electricity into the network during daylight hours; and

(b) the other profile is a non limited flat load profile and must be used for all other embedded generation that does not fit within the profile in paragraph (a) or if the reconciliation participant has not created an engineered profile for the embedded generator.

Compare: Electricity Governance Rules 2003 clause 2.5 appendix 1 schedule J5
Appendix 2
Determining statistically sampled profiles

1 Basic sampling scheme
The method of simple random sampling without replacement must be used in drawing statistical samples whenever such samples are required for profiles under this Code.

Compare: Electricity Governance Rules 2003 clause 1 appendix 3 schedule J5

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

\[ n_1 = \left( \frac{z_{\alpha}^2 \times C_A^2}{r^2} \right) \]

(2) If \( n_1/N \) is greater than 0.1, it must be modified to account for the finite population correction factor and is calculated as—

\[ n_1' = \frac{n_1}{1 + n_1/N} \]

(3) If either \( n_1 \) or \( n_1' \) is less than 20, the preliminary sample size must be 20.

(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 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:

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

(6) The profile acceptance limit must be 0.2.

(7) These values must be subject to review in accordance with clause 5.

(8) The profile applicant must collect half hour data from the preliminary sample over a period of at least 60 days. The data, in its processed form, must be submitted to the
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.

Compare: Electricity Governance Rules 2003 clause 2 appendix 3 schedule J5

3 Profile sample
(1) The size of the profile sample must be determined by the following profile sample size formula:

\[ n = \left( \frac{S_0^2}{Y_0^2} \right) \times \left( \frac{z_\alpha^2}{r^2} \right) \times \left\{ 1 + \frac{8 \times (r^2 / z_\alpha^2)}{S_0^2 / (n_1 \times Y_0^2)} \right\} + \frac{2}{n_1} \]

(2) If \( n/N \) is greater than 0.1, it must be modified to account for the finite profile population correction factor and is calculated as—

\[ n' = \frac{n}{1 + n/N} \]

(3) If either \( n \) or \( n' \) is less than \( n_1 \), the preliminary sample must become the profile sample.

(4) In the above formula—

- \( S_0 \) is the estimated standard deviation of unit costs from the preliminary sample, or from the existing profile sample in the case of updates
- \( Y_0 \) is the estimated mean of unit costs from the preliminary sample, or from the existing profile sample in the case of updates
- \( \alpha \) is the confidence level
- \( z_\alpha \) is the value of the standard normal distribution which gives \( \alpha \) probability outside the tails
- \( n_1 \) is the size of the preliminary sample, or the existing profile sample in the case of updates
- \( r \) is the relative standard error of the unit cost.

(5) The relative standard error (r) and the confidence level (\( \alpha \)) must be the same as those specified in clause 2.

(6) If the size of the profile sample is larger than the size of the preliminary sample, additional ICP identifiers from the profile population must be drawn to increase the sample size to the required level.

(7) Data from the profile sample must be used to form the basis for future updates.

Compare: Electricity Governance Rules 2003 clause 3 appendix 3 schedule J5
4 Sample updates

(1) If an update is required because of a change in the profile population, the following procedures must be followed:
   (a) if the size of the updated profile sample is larger than the size of the existing profile sample, additional ICP identifiers must be drawn from new participants of the profile population to increase the sample size to the required level;
   (b) if the size of the updated profile sample is smaller than the size of the existing profile sample, ICP identifiers from the existing profile sample must be removed to decrease the sample size to the required level, unless the profile applicant decides to nominate the existing profile sample as the profile sample.

(2) For the purposes of updates, data from the existing profile sample must be used (instead of data from the preliminary sample) in all profile sample size calculations.

Compare: Electricity Governance Rules 2003 clause 4 appendix 3 schedule J5

5 Reviews

(1) The statistical parameters must be monitored by the Authority and reviewed when the 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 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 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.

Compare: Electricity Governance Rules 2003 clause 5 appendix 3 schedule J5