Reconciliation Methodology Guidelines

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Disclaimer

This information paper is provided as general information only, and not as legal advice. It is not legally binding. If there is any inconsistency between the content of this information paper and the Code, the Code takes precedence.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ATH	Approved test house
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
GXP	Grid Exit Point
ICP	Installation Control Point
NSP	Network Supply Point
Registry	Electricity registry
Retailer	Electricity retailer

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Introduction

1. Ensuring that electricity generators or electricity buyers are allocated their correct share of electricity generation or consumption is a key role in operating an efficient market.

2. The reconciliation manager performs this allocation by receiving and processing large quantities of information derived from metering data on a monthly basis, reconciling it against a register of contracts, and passing the data on to industry participants.

3. Electricity is constantly transported over the national grid, but the sources of generation change many times over the course of a day. The reconciliation process involves detailed analysis to process and correct data for inaccuracies.

4. The reconciliation manager also processes the information for the clearing manager, who uses this information to credit generators for electricity generated, and to invoice electricity purchasers. NZX is currently contracted as the reconciliation manager.

5. The methodology followed by the reconciliation manager's system is described in this information paper.

Reconciliation

6. Partial retail competition commenced 1 October 1996. From this date, consumers whose site was metered by a half-hour certified metering installation could purchase electricity from any retailer that was willing to make an offer to them. Reconciliation was carried out by each network area by the network owner.

7. Full retail competition commenced on 1 April 1999. From this time, customers with ICP identifiers[1] could purchase electricity from any retailer that was willing to make an offer to them.

8. Before full retail competition commenced:

   (a) customers whose site was metered by non-half hour meters did not have choice of retailer. There was only one electricity retailer[2] operating within each network area.[3] Electricity was purchased by incumbent retailers from a net pool arrangement that became electricity market.

   (b) national reconciliation was not necessary, as the electricity that was conveyed within each network was the responsibility of only the one retailer. All losses[4] within each network area were the responsibility of the incumbent retailer.

9. When full retail competition commenced, independent retailers began to trade consumers within network areas, competing with incumbent retailers. A reconciliation

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[1] An ICP identifier is a unique 15 digit code that identifies a connection to a local or embedded network.

[2] This retailer was known as the incumbent retailer.

[3] Network area means a system of electricity lines, owned by the one network owner, that reticulated electricity from the grid to consumers and generators.

[4] Technical and non-technical (errors, omissions, theft, and fraud).

methodology was necessary to allocate the electricity conveyed by distributors to independent and incumbent retailers to allow electricity market charging to occur.

10. The New Zealand electricity market works on a gross pool basis: all generation conveyed over a consumer point of connection to the grid, local or embedded network must be sold to the clearing manager. Similarly all purchases conveyed over a consumer point of connection to the grid, must be made from the clearing manager.

11. Reconciliation is carried out monthly, and is a process of allocating physical volumes of electricity to retailers, purchasers, and generators. Participants must provide aggregated volume information[5] (called submission information) by the 4th business day of a month to the reconciliation manager for all of their points of connection to the grid, local or embedded networks, for the previous month. This is known as the initial submission and is termed R0.

12. Participants must also provide historic volume information to the reconciliation manager if they have carried out corrections or obtained meter readings by the 13th business day of a month. This process is called the revision process. The reconciliation manager reruns the reconciliation process for previous months. Each month the following revisions are carried out: day 4 submission (R1), and going back 3 months (R3), 7 months (R7), and 14 months (R14).

13. The purpose of the revisions is to ensure that any inaccuracies are corrected and, where non half-hour reads have been used, that allocations into months are corrected as meter readings become available.

14. This information paper describes:

    (a) the differencing reconciliation process that was used from 1 April 1999 to 30 April 2008

    (b) the current global reconciliation methodology that has been used since 1 May 2008.

Differencing reconciliation methodology

15. In the early stages of retail competition, it was both practical and reasonable to operate a methodology where the relatively small volume traded by an independent retailer was subtracted from the total injection to a network area. Independent retailers were then invoiced by the electricity market on the basis of the electricity sold to their consumers. However, incumbent retailers were invoiced on the residual amount that entered a network area from the grid, less that declared by independent retailers. This process was called differencing settlement and was determined by the following equation carried out for each trading period at each grid connection point.

Differencing reconciliation methodology settlement equation

$$P_{incumbent} = GXP_{metered} + \sum EG_{metered} - \sum P_{independent} - \sum PL_{independent}$$

[5] Determined from meter readings or, where those are not available, estimates and calculated unmetered load.

Where

$EG_{metered}$ =	volume of electricity from an embedded generator per trading period metered by an independent retailer
$GXP_{metered}$ =	volume of electricity per trading period metered for each grid connection point within a network area
$P_{incumbent}$ =	volume of electricity per trading period invoiced to the incumbent retailer
$P_{independent}$ =	volume of retailed electricity per trading period invoiced to the independent retailer, determined by meter readings from each retailer
$PL_{independent}$ =	volume of losses of electricity per trading period calculated by the independent retailer and invoiced to the independent retailer

16. However, issues were identified that caused increasing industry problems in many network areas follows. In summary, these issues were:

(a) Non-technical losses were automatically assigned to the incumbent retailer by this process.

(b) As competition and the number of independent traders increased, non-technical losses allocated to the incumbent retailer began to increase significantly.

(c) The accuracy of calculation of network loss factors could significantly advantage or dis-advantage incumbent retailers.

(d) Embedded generation that did not have half-hour metering could only be sold to the incumbent retailer.

(e) Embedded generation with half-hour metering could only be switched between retailers using a manual process.

(f) Embedded generation that did have half-hour metering had to be manually set up as a unique individual network supply point into the reconciliation system.

(g) Independent retailers were charged for only the volumes of electricity that they declared. Where an independent retailer omitted a multiplier, meter register, customer, incorrectly calculated loss factors, failed to read meters and only provided estimated readings etc, then the incumbent retailer was automatically charged for the volume of electricity not declared.

(h) The incumbent retailer had no visibility into independent retailers accuracy of providing information, and were forced to absorb the cost of independent retailer errors and omissions. Incumbent retailers were then at a purchasing disadvantage compared to independent retailers.

(i) Retailers applied network losses to their information before providing submission information to the reconciliation manager. Loss factors incorrectly applied by independent retailers in the application of network losses within network areas became non-technical losses allocated to the incumbent retailer.

(j) Poor data quality and records.

(k) Where electricity entered or exited a network area from another network, and not the grid, significant settlement problems occurred.

(l) Metering inaccuracy.

(m) Customer points of connection could be moved electrically between GXPs by networks.

(n) Incumbent retailers did not need to provide information to the reconciliation manager, making the tracing of errors difficult.

(o) Independent retailers' reconciliation information was not able to be verified against the registry which records the obligation to provide reconciliation information to the reconciliation manager.

Global reconciliation methodology

17. The industry recognised the problems, and a process was put in place to change the reconciliation methodology so that it would:

(a) identify and share non-technical losses amongst all retailers within a network area by trading period

(b) allow trading of any non half-hour metered embedded generation

(c) allow simple trading of any embedded generation by introducing the concept of bi-directional electricity flows at a consumer point of connection

(d) allow simple switching of customer points of connection that have embedded generation between retailers

(e) introduce scaling factors to penalise retailers where information provided into the reconciliation process is incorrect

(f) move the application of network losses from independent retailer systems to the central reconciliation process carried out by the reconciliation manager

(g) incorporate the ability to include flows of electricity between network areas that do not flow through the grid

(h) introduce the concept of balancing areas to remove the effects of a network moving electrically customer points of connection between GXPs

(i) require all retailers, purchasers, and generators to provide information to the reconciliation manager.

18. This reconciliation methodology was called global reconciliation with a gross pool financial model. It was determined by the following equation carried out for each trading period at each grid connection point.

Global reconciliation methodology settlement equation (simplified)

$$0 = GXP_{metered} + \sum IP_{enter} + \sum EG_{metered} - \sum P_{retailer} - \sum IP_{exit} \; +/- \sum UFE$$

Where

$EG_{metered}$ =	volume of electricity from an embedded generator per trading period invoiced to the retailer, determined by meter readings from each retailer, and loss adjusted by the reconciliation manager
$GXP_{metered}$ =	volume of electricity per trading period metered for each grid connection point within a network area
IP_{enter} =	volume of electricity that enters a network area from another network
IP_{exit} =	volume of electricity that exits a network area to another network
$P_{retailer}$ =	volume of retailed electricity per trading period invoiced to the retailer, determined by meter readings from each retailer, and loss adjusted and scaled by the reconciliation manager
UFE =	Unaccounted For Electricity. The balance volume of electricity required to "0" each trading period at each GXP, that is pro-rated between purchasers from the electricity market

19. The global reconciliation process went live on 1 May 2008 and has continued to operate since that time with no changes to the settlement equation. UFE is visible and can be readily viewed down to a balancing area or GXP level. The availability of this information allows the accuracy of network loss calculations, as well as improvements in settlement accuracy as advanced metering infrastructure is rolled out.

20. The advantages of global reconciliation over differencing reconciliation can be summarised as:

    (a) all participants buy and sell from the electricity market on the same terms

    (b) UFE is identified, is traceable, and is equitably allocated to purchasers

    (c) embedded generation is settled and switched as easily as consumption

    (d) settlements are accurate as it takes into account operational changes within network areas

    (e) network losses are accurately applied

    (f) scaling factors and participant audits provide a commercial incentive for traders to align their settlement records with the registry.

Requirements to be a reconciliation participant

21. For clarity, the following are the general requirements for a participant to [provide information to the reconciliation manager.

22. Part 15 of the Code sets out participant obligations in relation to reconciling submission information in the market. Reconciliation participants are a type of participant that have obligations under part 15 of the Code. These obligations are discussed further below.

Certification as a reconciliation participant

23. A purchaser at a network supply point (NSP) connected to the grid does not require certification as a reconciliation participant, as the grid owner provides metering information to the reconciliation manager and no interface with the registry is required.

24. A purchaser at an installation control point (ICP) is a reconciliation participant and is required to be certified for the following Code obligations:

    (a) maintaining registry information and performing customer and embedded generator switching

    (b) gathering and storing raw meter data

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

        (i) half hour volume information

        (ii) dispatchable load information

    (d) calculation of ICP days, monthly kWh information of half hour metered ICPs, and electricity supplied

    (e) provision of submission information for reconciliation

    (f) provision of metering information to the pricing manager in accordance with subpart 4 of part 13 of the Code.

25. Reconciliation participants must obtain and maintain certification to perform these functions in the electricity market. Certification requires having ISO 9001:2000 or ISO 9001:2008, or an Authority-deemed equivalent, and a suitable audit from an Authority approved auditor to show to the Authority's approval that the reconciliation participant complies with the Code.

26. Performing any functions of a reconciliation participant without the appropriate certification is a breach of the Code.

27. Purchasers who want to become certified reconciliation participants must apply to the Authority for certification two months before certification is required. However, new entrants must obtain certification no later than three months after the date on which they become reconciliation participants. Certification is granted for a period of no longer than 12 months.

28. Reconciliation participants can use agents to perform the functions in part 15 of the Code. However, responsibility under the Code still rests with the certified reconciliation participant, not the agent.

29. For further information, please refer to the information paper on audit and certification requirements for reconciliation participants and distributors.

30. For existing certified reconciliation participants seeking recertification, the application form for certification as a reconciliation participant must be submitted to the Authority two months before the reconciliation participant is required to be certified. The Authority uses the published certification dates on the certified reconciliation participant register as the due date for renewal applications for certification as a reconciliation participant.

31. Applications for certification must be submitted to the Authority. Details can be found on the Authority's retail audit database webpage.

32. If required, the clearing manager may be contacted at cmanager@nzx.com.

Notification to reconciliation manager of intention to purchase electricity

33. This section only applies to grid direct purchasers. It does not apply to purchasers or retailers that trader electricity at ICPs.

34. The reconciliation manager receives volume information in the form of submission information, dispatchable load information, or supporting information from all purchasers and sellers, and determines the amount of electricity purchased by each purchaser at each NSP.

35. A purchaser for a premises directly connected to the grid is required to notify the reconciliation manager of its intention to purchase or cease purchasing electricity on any NSP. A purchaser is also required to provide any information that is required by the Code or that is reasonably required by the reconciliation manager. The reconciliation manager must be notified at least five business days prior to the day the purchaser intends to purchase (or to cease purchasing) electricity at any NSP.

36. Notification to the reconciliation manager can be given via email to rm@nzx.com.

Provision of monthly information to the reconciliation manager

37. Purchasers (as reconciliation participants) must provide submission information and supporting information to the reconciliation manager in accordance with the Code and the reconciliation manager's functional specification.

38. The reconciliation manager's functional specification can be found on the Authority's website.

39. There are specific timeframes that must be met for the provision of this information.

40. Note that purchasers at an ICP must also deliver supporting information to the reconciliation manager as follows:

    (a) ICP days information for each consumption period

    (b) electricity supplied (billing) information

    (c) half hourly metered monthly ICP aggregates.

41. The reconciliation manager also has useful information on its website. Please contact the reconciliation manager directly to arrange logon access by emailing rm@nzx.com.

Profiles

42. The Code defines a profile as a “fixed or variable electricity consumption pattern assigned to a particular group of meter registers or unmetered loads”. Profiles apply to non half-hour meters only. 'Consumption pattern' means the way in which total electricity use for a certain period and group of users would be allocated across half-hourly time periods.

43. Standard profile shapes are available as follows:

    (a) *HHR (half hour):* for all hour submissions

    (b) *RPS (residual profile shapes):* standard non half hour profile shape that can be used for any non-half hour consumption submissions

    (c) *UML (unmetered load):* flat load profile that can be used for all unmetered load consumption submissions as an alternative to RPS

    (d) *PV1 (photovoltaic):* shaped profile that must only be used for all non-half hour metered photovoltaic generation submissions; this profile has an active period of 9am to 3pm

    (e) *EG1 (embedded generation):* flat load generation profile that must be used for all non-half hour generation submissions that are not photovoltaic.

44. Instead of using standard profiles, any retailer can introduce new profiles targeting specific groups. However, the majority of retailers use a profile based on the shape of all the electricity consumed at the local grid exit point, minus the electricity consumed by customers with half-hourly meters, known as the RPS.

45. Schedule 15.5 of the Code details how profiles are administered. An information paper and a list of approved profiles can be found on the Authority’s website.

46. All non half-hour profiles must follow the profile process set out in schedule 15.3. Particular attention should be paid to the use of the seasonal adjustment shape, and the forward and historic estimates in converting non half-hour meter readings into calendar month volumes. A guideline on the application of profiles is available on request to the Authority.

Reporting frequency of meter readings

47. Retailers must ensure that meters are read within specified time periods and must provide information to the Authority on the frequency of meter reading.

48. Guidelines and a format for submission of frequency meter readings are available on the Authority’s website.

49. Please send the information to marketoperations@ea.govt.nz.

Sources of information

50. Summary of sources of information contained in this information paper:

(a) Electricity Industry Act 2010: http://www.legislation.govt.nz/

(b) The Electricity Industry (Enforcement) Regulations 2010

(c) Electricity Industry Participation Code 2010

(d) Reconciliation information (profile information and frequency meter reading)

(e) Reconciliation participant certification and audit requirements

(f) Reconciliation manager functional specification: http://www.ea.govt.nz/dmsdocument/961

(g) Reconciliation manager website: https://electricityreconciliation.co.nz/page/home

(h) Reconciliation system user manual: https://www.electricityreconciliation.co.nz/page/download_static?filename=NZX_RM_User_Guide_v1.1.pdf

(i) Retail information (general)

(j) Wholesale information (general).

51. The Authority publishes a weekly Market Brief. This is designed to provide individuals, businesses, and groups with regular updates and information on a variety of topics in relation to the Authority and its work plan.

52. If you require further information, please contact the Market Operations Team:

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