Guidelines on the calculation and use of loss factors for reconciliation purposes

26 June 2018

Version control

Version	Date amended	Comments
1.0	15 June 2007	Draft for consultation.
2.0	12 June 2008	Draft for Board approval.
2.0	18 September 2008	Board approved. Updated with Commission style.
2.1	1 November 2010	Updated for transition to Electricity Authority and amendments to part E of the Electricity Governance Rules 2003.
2.2	14 February 2013	Major restructure and rewrite based on the work of the Loss Factor Review Panel. Some template and style changes brought about the change from the disestablishment of the Electricity Commission and establishment of the Electricity Authority. This version is not approved; it is a draft for consultation.
2.3	26 June 2018	Amendments made after consultation.

Overview

1. These guidelines have been produced to promote understanding and encourage consistency in the calculation methodology and processes surrounding distribution loss factors.

2. These guidelines recommend:

   (a) a methodology for calculating **reconciliation loss factors**

   (b) an annual loss factor report.

3. Distribution loss factors are important in the reconciliation of electricity purchases. The **reconciliation loss factor** is used in:

   (a) the reconciliation process by the reconciliation manager to allocate volumes of electricity at GXPs to participants (both buyers and sellers from/to the clearing manager)

   (b) the retail pricing process by retailers for the sale of electricity to consumers

   (c) in the case of GXP charging networks, the calculation of network charges.

4. Loss factors directly impact on the cost of electricity faced by all consumers. The estimated spot market value of losses in distribution networks for 2011 was $118 million.[1] Distribution losses are believed to be 5.4 % of the energy conveyed on distributors' networks in 2011.[2]

5. Distributors populate loss factors in the registry, as required by the Electricity Industry Participation Code 2010 (Code). Further detail on Code requirements is provided in Appendix A.

6. The application of these Guidelines in no way reduces the requirement on participants to comply with their obligations under the Code. These guidelines do not necessarily reflect the Authority's views about the Code. In the event of any inconsistency between these guidelines and the Code, the Code prevails.

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[1] Derived from 1603.2 GWh (distribution losses reported to the Commerce Commission) multiplied by $72.30 per MWh (average of daily demand weighted spot prices).

[2] Sourced from figure G.4 of the New Zealand Energy Data File (2011 calendar year edition)

Contents

Introduction

1. These guidelines are recommended for use by distributors when calculating and publishing distribution loss factors.

2. Compliance with these guidelines is not mandated within the Code.

3. These guidelines have been developed to allow flexibility in application. The degree of complexity can be chosen depending upon the distributor's network size and configuration, staff resources, software tools and data availability.

4. These guidelines are intended to be consistent with the Code and the Model Use of System Agreement (MUoSA). Compliance with the MUoSA requires calculating loss factors in accordance with these guidelines.

5. The Code can be found on the Authority's website at: http://www.ea.govt.nz/act-code-regs/code-regs/the-code/.

6. The version of these guidelines and work books used during consultation can be found on the Authority's website at: https://www.ea.govt.nz/operations/distribution/losses/.

7. Where words appear in **bold** font, this indicates that the words are defined in paragraph 17 of these guidelines. Terms defined in the glossary of these guidelines or Part 1 of the Code are used, but do not appear in bold font.

8. Throughout these guidelines, hyperlinked cross-references have been used. Simply click on the link to be taken to the relevant part of the document.

9. If you require further assistance, please send an email to marketoperations@ea.govt.nz.

Applicability of these guidelines

10. Distributors who own/operate a local network should determine loss factors in accordance with the main body of these guidelines.

11. Distributors who own/operate an embedded network should determine loss factors in accordance with Appendix B - *Loss factor methodologies for embedded networks*.

12. These guidelines do not apply to any other participants including islanded networks and the grid owner.

Purpose of these guidelines

13. Distribution loss factors are important because:

    (a) purchasers of electricity pay for the losses associated with delivery of their electricity

    (b) the amount paid to sellers of electricity from embedded generators is scaled up or down by the associated loss factor

    (c) in the case of GXP charging networks, loss factors are used in the calculation of network charges

    (d) loss factors are used in the retail pricing process by retailers for the sale of electricity to consumers.

14. Loss factors directly impact on the cost of electricity faced by all consumers. The estimated spot market value of losses in distribution networks for 2011 was $118 million.[3] Distribution losses are believed to be 5.4% of the energy conveyed on distributors' networks in 2011.[4] Consumers face the cost of all losses, whatever the cause.

15. Improved knowledge of **technical loss** will enable greater understanding of the location and level of losses within network areas. This will also lead to the identification of **non-technical loss**. A separate guideline will be developed for the determination of technical loss factors.

16. The Authority intends to monitor the volume and percentage of **non-technical loss**. The Authority will discuss any inappropriately high **non-technical loss** with the relevant participants with a view to minimisation, and could ultimately be investigated via an audit.

Defined terms

17. The following terms are used in these guidelines.

    (a) **"Individually calculated customer" (ICC)** means a customer with a point of connection to a local network or embedded network for whom the relevant distributor has chosen, or is required to, calculate a site specific **reconciliation loss factor**. An **ICC** may consume electricity, generate electricity or do both.

    (b) **"Load factor" (LF)** means the ratio between the average load and the peak load. It is typically calculated using half hour data. **Load factor** can be calculated in accordance with the following equation:

[3] Derived from 1603.2 GWh (distribution losses reported to the Commerce Commission) multiplied by $72.30 per MWh (average of daily demand weighted spot prices).

[4] Sourced from figure G.4 of the New Zealand Energy Data File (2011 calendar year edition)

Equation 1

$$LF = \sum_{n=1}^{THH} \left(\frac{Load_n}{Peak\ Load}\right) / THH$$

Where:

- $Load_n$ = the 30-minute average load in the nth period
- Peak Load = the highest 30-minute average load.

(c) **"Load loss"** (also sometimes referred to as 'copper losses') means the loss arising from the heating effects of the resistance in the network conductors. **Load loss** is proportional to the square of the current and occurs in the subtransmission, HV and LV network conductors, and zone substation and distribution transformers.

(d) **"Loss load factor" (LLF)** means the ratio between average **load loss** and peak **load loss**. It is typically calculated using half hourly data. **LLF** can be calculated in accordance with the following equation:

Equation 2

$$LLF = \sum_{n=1}^{THH} \left(\frac{Load_n^{\ 2}}{Peak\ Load^2}\right) / THH$$

Where:

- $Load_n$ = the 30-minute average load in the nth period
- Peak Load = the highest 30-minute average load

(e) **"Network segment"** is used to describe any part of a **network study area** that the distributor has allocated a separate loss factor for. Typically, this would be based on voltage tier.

(f) **"Network study area"** is used to describe the network area for which a set of loss factors are calculated. It will be supplied by either a single GXP, or a group of GXPs. Distributors may have multiple **network study areas**.

(g) **"No load loss"** (also sometimes referred to as 'iron losses') means the loss arising from the energy consumption necessary to energise the zone substation, distribution transformers, voltage regulators, auto transformers and isolating transformers. For the purposes of these guidelines, losses associated with capacitors, insulation dielectric and minor network equipment may be ignored.

(h) **"Non-technical loss" (NTLF)** means a loss that represents inaccuracies in measurement and data handling processes (e.g. metering and meter reading errors, inaccurate metering installations, theft, and unread meters). It is calculated as the difference between **RL** and **TL**.

(i) **“Reconciliation loss” (RL)** means the difference between energy injected into the **network study area** and energy delivered to the points of connection within that **network study area** as reported by traders to the reconciliation manager.

(j) **“Reconciliation loss factor” (RLF)** means the multiplier to be applied to the volume of energy measured at a point of connection (POC) within a **network study area** to scale the volume to account for the attributed **reconciliation loss** relevant to that POC. **RLFs** can be calculated in accordance with the following equations:

Equation 3

$$RLF = \frac{Volume\,at\ POC + Attributed\,RL}{Volume\,at\ POC}$$

Equation 4

$$\mathrm{RLF} = \frac{1}{(1 - \mathrm{RLR})}$$

(k) **“Reconciliation loss ratio” (RLR)** means the ratio of **RL** attributed to a POC, to the sum of the volume measured at that POC and the attributed **RL**. **RLRs** can be calculated in accordance with the following equation:

Equation 5

$$\mathrm{RLR} = \frac{\mathrm{Attributed\ \ RL}}{\mathrm{Volume\ \ at\ POC + Attributed\ \ RL}}$$

(l) **“Total hours” (TH)** means the number of hours in the relevant year.

(m) **“Total half hours” (THH)** means the number of 30-minute load recordings in the relevant year.

(n) **“Technical loss” (TL)** means a loss resulting from **load losses** and **no load losses** between the parent NSP and the POC.

(o) **“Technical loss factor” (TLF)** means a multiplier to be applied to the electricity delivered or injected at a POC within a **network study area** to scale the volume to account for attributed **TL** between that POC and the parent NSP. **TLFs** can be calculated in accordance with the following equations:

Equation 6

$$TLF = \frac{Volume\,at\ POC + Attributed\,TL}{Volume\,at\ POC}$$

Equation 7

$$TLF = \frac{1}{(1 - TLR)}$$

(p) **"Technical loss ratio" (TLR)** means the ratio of **TL** attributed to a POC, to the sum of the volume measured at that POC and the attributed **TL**. **TLRs** can be calculated in accordance with the following equation:

Equation 8

$$\mathrm{TLR} = \frac{\mathrm{Attributed\ TL}}{\mathrm{Volume\ at\ POC} + \mathrm{Attributed\ TL}}$$

(q) **"Utilisation factor" (UF)** means, in relation to a transformer, the ratio between its peak load (kVA) and its rated capacity (kVA)[5]. **UF** may be calculated for zone substation transformers and for distribution transformers. Note that this **UF** (typically about 60–80 %) is not to be confused with the after diversity **UF** published in distributors' information disclosures (typically about 30–40 %).

There are four types of losses within a network

18. In the context of electricity distribution and the New Zealand electricity reconciliation system, losses of electricity can be categorised into:

    (a) technical losses

    (b) non-technical losses

    (c) reconciliation losses

    (d) unaccounted for electricity (UFE).

19. Technical loss is the difference between energy actually injected into a network and energy actually delivered to points of connection. Technical loss results from load losses (also known as copper losses) and no load losses (also known as iron losses). These are the losses that arise from the use of network equipment and are a function of the physical characteristics of the network equipment invested in by the network owner.

[5] If the peak load is available only in kW, use an appropriate power factor to determine kVA.

20. Non-technical loss is the difference between the volume of energy actually conveyed at points of connections and the volume of energy reported as conveyed at the same points of connection (as stated by traders in their submission information submitted for the purpose of the reconciliation process). Non-technical loss is any form of unexplained losses, such as:

    (a) metering inaccuracy, regardless of:

        (i) the size of inaccuracy and whether it is compliant with the accuracy requirements of the Code; or

        (ii) the source of inaccuracy, whether it be tampering, faulty equipment, poor installation or misconfiguration; and

    (b) errors or omissions in traders' back office systems.

21. Reconciliation loss is the difference between reported energy injected into a network[6] and the reported energy extracted from the network.[7] Reconciliation loss is the combination of technical and non-technical losses.

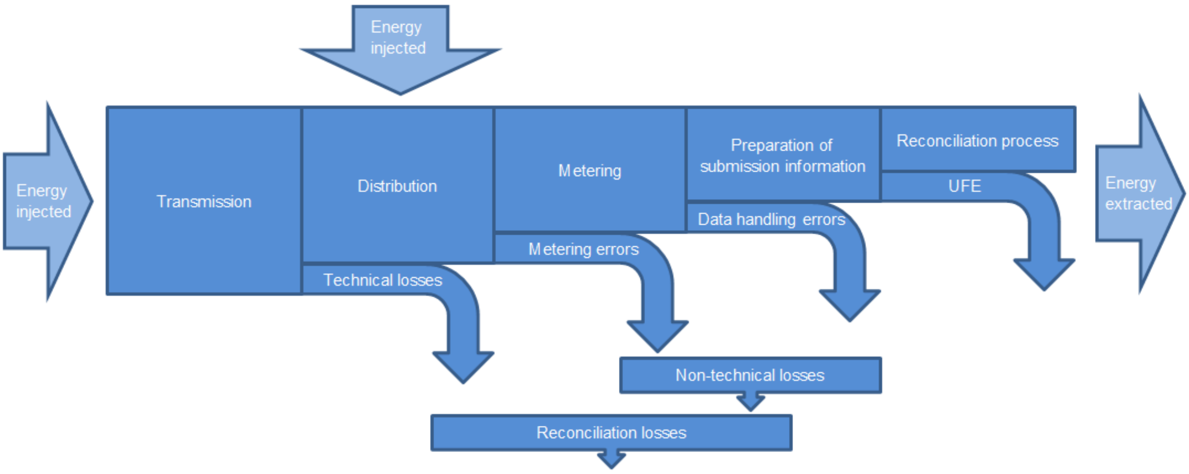
22. UFE is calculated from the difference between reported energy injected into a network and the reported energy extracted from the network after it has been adjusted for losses. Conceptually, it is the inevitable difference between distributors' predictions and reported reality (volumes as measured by meters). UFE accounts for the difference between actual and calculated technical losses, and actual and estimated non-technical losses.

23. Figure 1 illustrates 'where' the different types of losses occur, though the figure itself is a blend of representing physical conveyance of electricity and information flows representing physical conveyance of electricity.

[6] As reported to Transpower ascertained from grid-level metering and traders on behalf of embedded generators ascertained from ICP-level metering.

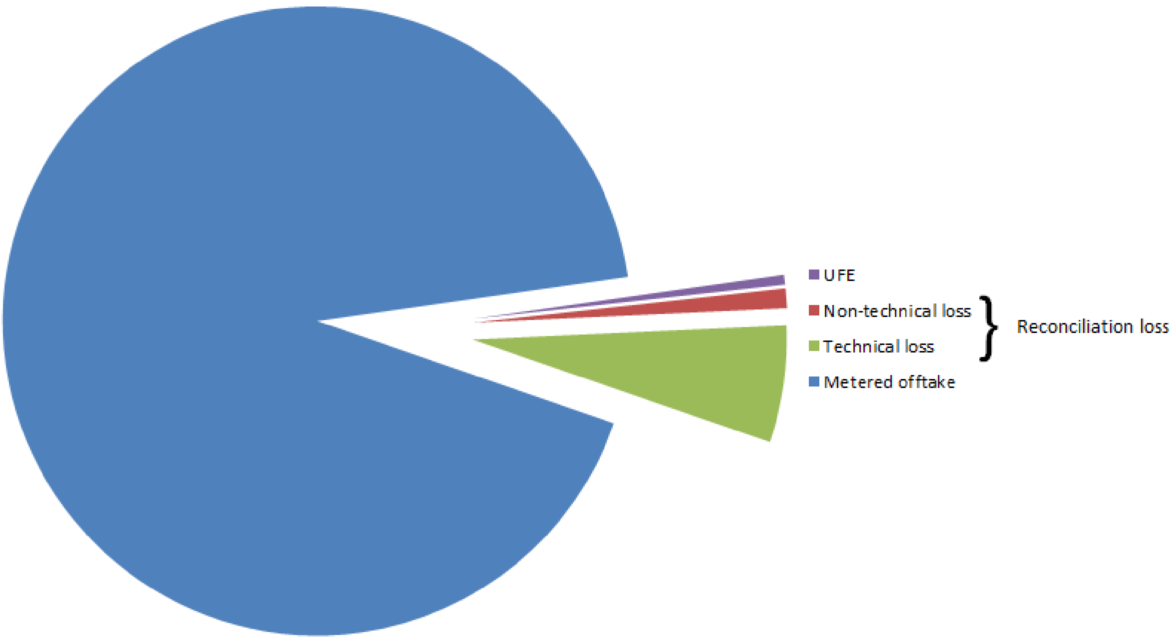
[7] As reported by traders on behalf of their consumers ascertained from ICP-level metering.

Figure 1 – Distribution losses of electricity in New Zealand



24. Figure 2 illustrates how the total electricity injected into a distribution network is typically reconciled. It also demonstrates how technical losses, non-technical losses, and UFE combine to represent the total loss within a distribution network.

Figure 2 – Typical reconciliation of electricity injected into a network



Note: The UFE represented in the figure is positive UFE. Negative UFE occurs when traders overstate volumes purchased and/or distributors overestimate loss factors.

Note: Technical and non-technical losses are not separately identifiable in the reconciliation process. The loss factors entered on the registry by the distributor determine the reconciliation loss.

Consumers pay for all losses

25. Distributors are required by the Code to assign every point of connection a loss category code and associated loss factors.[8] A loss factor is a multiplier used in the reconciliation process to adjust metered volumes (submission information) to account for losses.

26. Loss factors directly impact on the cost of electricity faced by all consumers. The estimated spot market value of losses in distribution networks for 2011 was $118 million.[9] Distribution losses are believed to be 5.4 % of the energy conveyed on distributors' networks in 2011.[10] Consumers face the cost of all losses, whatever the cause. For most consumers, this cost is bundled in the price per kWh they pay their retailer.

27. The cost paid by retailers is a function of the loss factors entered in the registry and the UFE attributed to each retailer.

28. Therefore, to achieve efficient prices it is important that losses are accurately represented by loss factors and that the costs of inefficient or undesirable losses are not incurred. The accurate and timely determination of loss factors and associated reporting are a critical part of achieving loss factors that:

    (a) result in annual UFE being close to zero

    (b) improve the allocation of costs between consumer classes

    (c) assist in identifying non-technical losses that can then be eliminated, where economical.

29. Currently the Code requires distributors to populate the registry with loss category codes and associated loss factors. The Code does not stipulate the methodology used to calculate loss factors, nor the required level of accuracy.

30. The guidelines provide the only reference for distributors to follow in determining loss factors. The updated guidelines have been written with this in mind and provide more information on the recommended methodology for calculating loss factors, and reporting considerations.

Use of distribution loss factors

31. Distribution loss factors are used in the reconciliation of electricity purchases. The **reconciliation loss factor** is used in:

    (a) the reconciliation process by the reconciliation manager to allocate volumes of electricity at GXPs to participants (both buyers and sellers from/to the clearing manager)

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8 Refer to clause 7(1)(e) of Schedule 11.1 of the Code.

9 Derived from 1603.2 GWh (distribution losses reported to the Commerce Commission) multiplied by $72.30 per MWh (average of daily demand weighted spot prices).

10 Sourced from figure G.4 of the New Zealand Energy Data File (2011 calendar year edition).

(b) the retail pricing process by retailers for the sale of electricity to consumers

(c) in the case of GXP charging networks, the calculation of network charges.

32. Loss factors directly impact on the cost of electricity faced by all consumers. The estimated spot market value of losses in distribution networks for 2011 was $118 million.[11] Distribution losses are believed to be 5.4 % of the energy conveyed on distributors' networks in 2011.[12]

33. Distributors populate loss factors in the registry, as required by the Code. Further detail on Code requirements is provided in Appendix A.

Introductory considerations

34. This section introduces:

(a) the calculation methodology;

(b) the considerations around disaggregating a network into appropriate groupings for loss calculation;

(c) datasets that should be used in the calculations.

Overview of calculation methodology

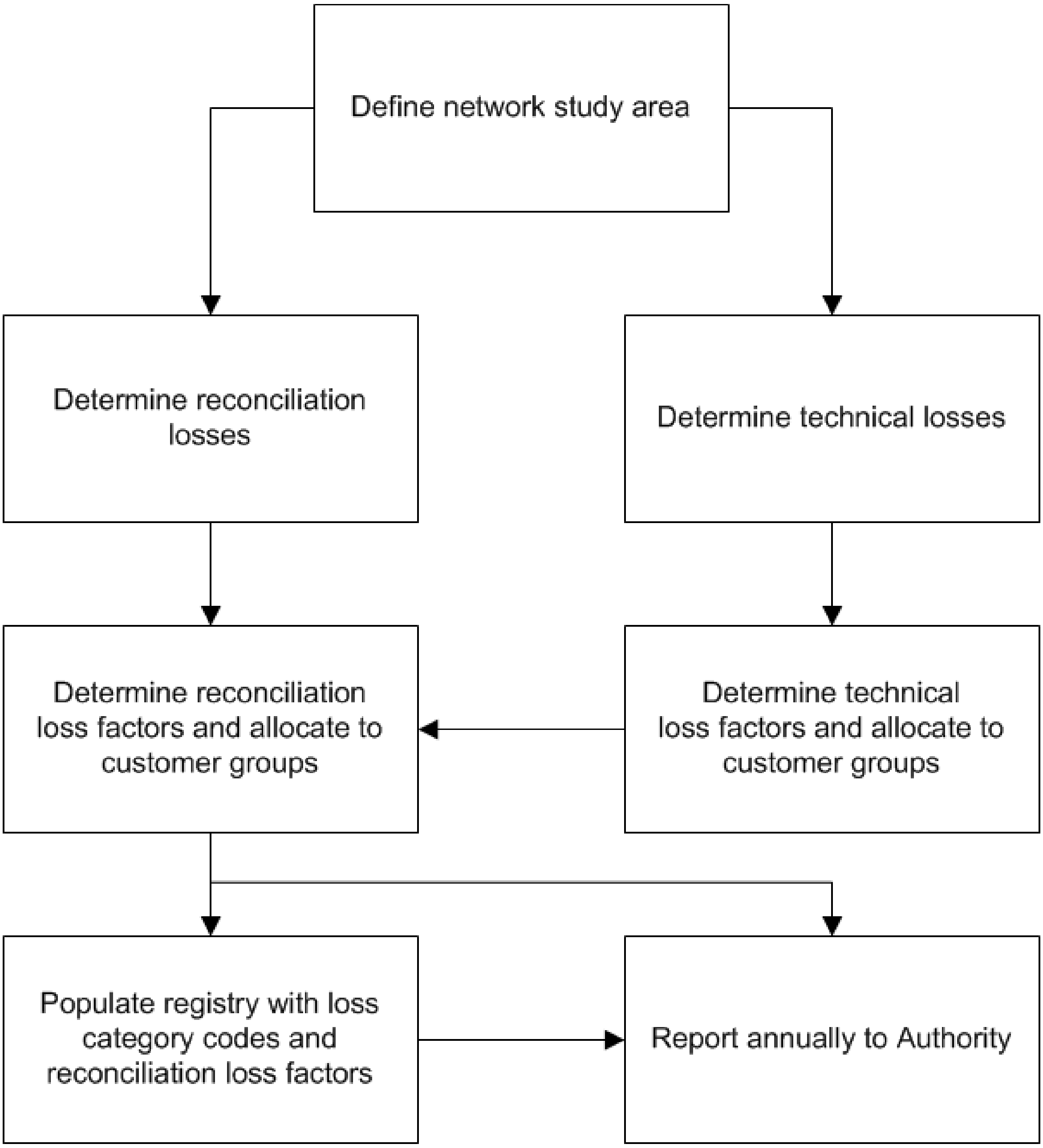
35. The methodology used in these guidelines is to determine **RL** to produce **RLFs** based on the **RL** and **TLFs** calculated for each **network segment** of the **network study area**.

36. Figure 3 below illustrates the flow of the key tasks involved for a distributor implementing these guidelines.

[11] Derived from 1603.2 GWh (distribution losses reported to the Commerce Commission) multiplied by $72.30 per MWh (average of daily demand weighted spot prices).

[12] Sourced from figure G.4 of the New Zealand Energy Data File (2011 calendar year edition).

Figure 3: Flowchart of key tasks



Disaggregating the network study area

37. A distributor may determine the appropriate degree of disaggregation of its network into the **network study area**. The degree of disaggregation determines the number of loss factors.

38. The level of disaggregation can be expressed as a continuum between:

    (a) complete aggregation - one loss factor applies to every point of connection on the network for all half hour periods

    (b) complete disaggregation – a different loss factor applies to each point of connection for each half hour period.

39. Neither complete aggregation nor complete disaggregation is appropriate. Complete aggregation would see cross-subsidisation amongst consumers. Complete disaggregation, even if it were possible, would produce a solution at excessive expense and complexity.

40. Each network has its own characteristics that will be driven by factors like seasonal variations, load density, large individual loads and generation, voltage connection tier, industry intensity, and **load factors**. Distributors are expected to consider such characteristics when determining the appropriate level of disaggregation.

Technical losses

41. Determining **TL** is an important step in determining **RLFs**. Distributors should use a recognised method for calculating or assessing technical losses. A more detailed technical loss calculation may be warranted if a distributors total loss factors are significantly higher when compared to a similar distributor.

42. Distributors should review **TL** every five years. If there is a significant change in network configuration and/or load within the five year period, the **TL** should be reviewed and updated.

43. Technical loss factors are complex to determine accurately. It is expected that distributors will calculate a **TLR** for the entire **network study area** within ±20% given the accuracy of the assumptions that will be required and the capability of load flow software. This means that if a **TLR** for the entire **network study area** is calculated to be 5%, then the actual **TLR** will lie between 4 % and 6 %.

44. **TL** is made up of two components: **load loss** and **no load loss**. These are considered separately as set out below.

Load loss

45. Distributors may calculate peak **load loss** for each **network segment** at peak demand for that **network segment** using a suitable load flow package.

46. Distributors may calculate the associated annual energy losses using peak **load loss** and applying the appropriate **LLF** as follows:

Equation 9

Annual load loss (kWh) = Peak load loss (kW) x TH (hrs) x LLF

47. Distributors may calculate the **LLF** for each **network segment** where different load profiles exist and supporting data exists. Examples of supporting data are the previous year's SCADA data, half hourly metering data or other assumed profiles.

48. Distributors may calculate annual **load loss** for each **network segment**.

No load loss

49. Distributors may calculate the annual **no load loss** as follows:

Equation 10

Annual no load loss (kWh) = No load loss (kW) x TH (hrs)

Where **no load loss** (kW) is the sum of the **no load loss** for each transformer in the **network segment**.

50. Distributors should not apply the **LLF** to **no load loss** (kW) as these losses are not dependent on loading.

Datasets to use in the calculation

51. The correct and consistent use of datasets in the analysis is important. For the purpose of these guidelines, the Authority recommends that distributors use historical metered data.

52. For the purpose of calculating **RLFs**, the Authority recommends that trader reconciliation submission information[13] is used, but only after it has gone through the seven month revision. The use of submission data requested from retailers to calculate losses. Submission data is aggregated by loss category code, GXP, and flow direction. Use of submission data will enable distributors to determine electricity flows at a more granular level.

53. The exception to the use of historical data is where large changes on a network are expected to occur. This will happen when either a large new load or generation is being connected that will lead to network flows which are substantially different from historical flows. In these cases. Distributors should model a forecast of the demand and new generation when determining loss factors.

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[13] For more detail on the GR260 file, refer to the reconciliation functional specification available from http://www.ea.govt.nz/industry/mo-service-providers/reconciliation-market-operation-service-provider/reconciliation-functional-specifications/

54. Where such changes occur, it is recommended that distributors update the loss factors on that **network study area** just prior to the change occurring.

Site specific technical losses

55. This section presents two methodologies that may be used to calculate site specific **technical losses** for **ICCs**: the pro-rated and incremental methodologies.

56. The pro-rated methodology is simpler and usually sufficient as a measure of site specific loss factors. However, where the customer requires a new or upgraded connection, it may be more appropriate to use the incremental methodology. More information on these methodologies is provided in the relevant sections below.

57. For embedded generators of 10 kW or more, but less than 1 MW, the distributor should determine whether to:

    (a) adopt an **RLF** equal to the **TLF** determined for the general consumption for that point of connection; or

    (b) calculate a site specific **RLF**.

58. For embedded generators of 1MW or more, the distributor should calculate a site specific **RLF**.

59. The Code requires a unique loss category code to be assigned to an ICP that connects an embedded generating station with a capacity of 10MW or more to the distributor's network.

60. Where the embedded generation reduces network losses, the **RLF** will be greater than 1.00. Conversely, where the embedded generation increases network losses, the **RLF** will be less than 1.00.

61. The Authority recommends that distributors calculate site specific loss factors for any interconnection points involving their network. Accordingly, the Authority recommends that distributors on either side of an interconnection point communicate and collaborate with one another to determine **RLFs** in a way that satisfies the distributors involved while maintaining compliance with the Code and these guidelines.

62. Losses directly associated with an **ICC's** consumption need to take into account the point on the network where the **ICC** is connected (eg, subtransmission level, zone substation level), the location of the metering installation for the **ICC** and whether the metering installation includes loss compensation.

63. Distributors should only calculate losses associated with an **ICC's** consumption from the upstream network. For example, if an **ICC** is connected to an 11kV zone substation bus, only losses in the subtransmission lines and zone substation transformers should be considered.

64. The annual losses and consumption associated with the **ICC** are removed from the total losses and total energy consumption for the relevant **network segments**. The remaining losses and energy are used to calculate **TLRs** and **TLFs** for the remaining load.

Site specific losses based on pro-rated peak demands

65. The calculation of a site specific loss factor based on pro-rated peak demands does not apply to determining embedded generator loss factors.

66. Where an asset supplies non-site specific load and one or more **ICCs**, a distributor needs to allocate all the losses. One way to achieve this is to allocate losses based on peak demand. For example, consider an **ICC** with a 10 MW peak demand connected at 33kV with a 15 MW peak demand. If the peak **TL** in **network segment** 'A' is 480 kW, then the peak **TL** attributable to the **ICC** for **network segment** 'A', pro-rated by peak demand is:

Equation 11

$$480\,kW x \frac{10MW}{15MW} = 320\,kW$$

67. A distributor should convert the above peak demand and attributed peak loss into energy losses per annum per Equation 9. If the load is connected at a **network segment** lower than 'A', a distributor needs to allocate losses to each **network segment** upstream of the load.

68. A distributor should calculate a site specific **TLF** from the results of paragraph 67 per Equation 12.

Equation 12

$$TLF \;\; for\ ICC = 1 + \frac{\sum losses(kWh)\ attributable\ to\ ICC}{\sum energy\ consumption(kWh)\ for\ ICC}$$

Site specific loss factor based on incremental impact

69. A distributor may need to undertake a loss calculation based on incremental effects if the load or generator is large in relation to other loads in the network. In such cases, specific investment in cables, lines and/or transformer capacity may be required to provide an adequate network connection.

70. Incremental calculations become complex, especially if two or more incremental calculations overlap.

71. In determining the incremental impact of an **ICC** load, a distributor should attribute a share of the **no load loss** at a zone substation and distribution transformer (if relevant) on a pro-rated peak demand basis, even though, strictly speaking, this **no load loss** is constant and independent of demand.

72. To determine the incremental impact of an **ICC**, for either load or generation, the distributor should:

   (a) determine several points along the **ICC's** load (or generation) duration curve representing the expected performance of the **ICC**

   (b) for each point of consumption or generation from (a) calculate the incremental losses in each affected **network segment**

   (c) calculate annual **TL** by totalling time weighted results from (b).

73. The following example illustrates the incremental methodology by calculating the appropriate loss factor for a 14 MW embedded wind generator. The generator is significantly larger than the load connected to the nearby network.

74. Network losses are dependent on the size of both background network load and generation. In order to accommodate this variability, the distributor may carry out modelling for a matrix of scenarios; zero, low, medium and high values for generation, and low, medium and high values for load. Twelve loss calculations are required.

Table 1: Scenario matrix

	Site specific generator			
Background load	None	Low	Med	High
Low				
Med				
High				

75. 'Low', 'medium', and 'high' are defined by percentile values for both background load and generation and consideration of cross-correlation between the background load and generation.

76. For this example, the percentile values considered for both generation and background load are P15, P60, and P95. In the case of this example, this corresponds to generator outputs of 2 MW, 5 MW, and 13 MW respectively. Time weighted totals and consideration of correlation between background load and generation show the benefit of increasing generation at high background load times.

77. This particular example assumes no correlation between background load and generation.

78. Three background load and four generation scenarios are used in this case, although other selections may be appropriate.

79. In relation to the background load, the three scenarios selected were P15 (15th percentile, representing P0 to P30, applying 30 % of the time, 2628 hours), P60 (60th percentile,

representing P30 to P90, applying 60 % of the time, 5256 hours) and P95 (95th percentile, representing P90 to P100, applying 10 % of the time, 876 hours). The same three ‘P’ values were used for the wind generator, plus a ‘zero’ generation option as the base case, to determine the initial network losses without the generator present.

80. To help make the units clearer the example here uses an annual period described in hours. It would of course be reasonable to use percentages rather than hours, should that be desirable (say for an analysis period of other than one year).

81. In this case, being a wind turbine, there would be no correlation between load and generation profiles.

82. On the other hand, a gas turbine, or hydro with storage, could be managed to match the load to achieve positive correlation. But a solar generator would likely have a negative correlation to background load, given that load rises on colder, cloudy winter days, or at night.

83. Only the network affected by the varying generator output needs to be modelled (spurs and downstream network need only have their loads summed at the take-out points). This reduces the size of the required load flow model.

84. The network model was run 12 times: three representing the base case (no generation), and nine times representing the three generation and three load combinations. A branch **load loss** summary table is produced below. Only **load loss** needs to be considered in the model as **no load loss** is independent of load variation.

Table 2: Branch loss summary (kW)

	Generation			
Load	None	P15	P60	P95
P15	**760**	**760**	**1,080**	**1,860**
P60	**840**	**820**	**1,090**	**1,820**
P95	**1,060**	**1,020**	**1,190**	**1,820**

85. Each element of the branch loss summary is the sum of the losses for that particular generation and load scenario.

86. Total losses with and without generation are calculated by multiplying Table 2 by either Table 3, Table 4 or Table 5 depending on the correlation scenario chosen.

87. A matrix suitable for a wind generator or run of river hydro (where no correlation exists between the load and generation) is set out below. The result elements are the expected number of hours per year that each scenario is valid. Each bolded number in Table 3 below is the time that particular load and generation scenario exists (e.g. the first element 788 hours is the product of

30% * 30% * 8760 hours). For random type generation (e.g. wind), it is presumed no correlation exists between load and generation as expressed in Table 3.

Table 3: Scenario matrix (No correlation) (Hours)

		Generation Scenarios			
		No Gen	Low – P15	Med – P60	High – P95
Load Scenarios			30%	60%	10%
Low – P15	30%	***2,628***	***788***	***1,577***	***263***
Med – P60	60%	***5,256***	***1,577***	***3,154***	***526***
High – P95	10%	***876***	***263***	***526***	***88***

88. Table 4 below shows high positive correlation where the generator is managed to match its output to the network load.

Table 4: Scenario matrix (High positive correlation) (Hours)

		Generation Scenarios			
		None	Low	Med	High
Load Scenarios			30%	60%	10%
Low – P15	30%	***2,628***	***2,628***	***0***	***0***
Med – P60	60%	***5,256***	***0***	***5,256***	***0***
High – P95	10%	***876***	***0***	***0***	***876***

89. Table 5 below shows high negative correlation where the generator output is low when the network load is high, and high when the network load is low.

Table 5: Scenario matrix (High negative correlation) (Hours)

		Generation Scenarios			
		None	Low	Med	High
Load Scenarios			30%	60%	10%
Low – P15	30%	***2,628***	***0***	***1,752***	***876***
Med – P60	60%	***5,256***	***1,752***	***3,504***	***0***
High – P95	10%	***876***	***876***	***0***	***0***

90. Continuing with the wind generator example and using Table 2 and Table 3, Table 6 is calculated by multiplying each loss scenario by duration. The loss is calculated for each of the ‘no generation’ and ‘with generation’ scenarios by totalling each of the columns.

Table 6: Time weighted loss summary

	Generation Scenarios (MWh)			
Load	None	P15	P60	P95
P15	1,997	599	1,703	489
P60	4,415	1,293	3,438	957
P95	929	268	626	160
Sum	7,341	2,160	5,767	1,606

Equation 13: Calculation of the sum of losses under generation scenarios

$$Sum\ of\ \ network\ loss\ with\ generation = \sum P15, P60, P95\ scenario\ sums$$

91. Equation 13 is: 9,533 MWh = 2,160 MWh + 5,767 MWh + 1,606 MWh

92. This calculation shows that the generator is expected to cause additional network losses (ie, the annual losses with generation are greater than the annual losses with no generation). However, in other circumstances, it is possible that generation would reduce network losses, particularly where the generator is smaller, or about the same size as the network load near it.

Equation 14: Calculation of network loss due to generation

$$Network\ loss\ due\ to\ generation = Sum\ of\ \ network\ loss\ with\ generation - Sum\ of\ \ network\ loss\ without\ generat$$

93. Equation 14 is: 2,192 MWh = 9,533 MWh – 7,341 MWh

Equation 15: Calculation of time weighted annual generator output

$$Annual\ generator\ output\ (MWh) = \sum (Generation\ output(MW) \quad x \quad respective\ duration(hrs))$$

94. The purpose of Equation 15 is to sum the annual output of the generator. For the wind generator above, the inputs to Equation 15 are shown in Table 7.

Table 7: Generation output scenarios

Generation scenario (output MW generated)	Hours per year generator operates at that scenario	Generator output (MWh)
P15, 2 MW	2,628	5,256
P60, 5 MW	5,256	26,280
P95, 13 MW	876	11,388

95. Using Table 7, the result of Equation 15 is: 42,924 MWh = 5,256 MWh + 26,280 MWh + 11,388 MWh

96. Note that in the use of the formulae for **TLR** and **TLF** for generators, care is required in the treatment of the signs associated with losses and generator output. In summary:

    (a) increased network loss is positive

    (b) reduced network loss is negative

    (c) generator output is negative, as it is treated as a negative load.

Equation 16: Calculation of TLF for generator

$$TLF = 1 + \frac{Network\,loss\;due\;to\;generation(MWh)}{Annual\;generator\;output(MWh)\quad x \quad -1}$$

97. If a generator reduced the losses in a network then the "Network loss due to generation" in Equation 16 would be negative and **TLF** will be greater than 1.0.

98. For the wind generator example, the result of Equation 16 is: 0.9489 = 1 + (2,192 / 42,924 x -1)

99. The result of Equation 16 is then used as the **TLF** for the **ICC**.

Equation 17: Calculation of TLR for generator

$$TLR = \frac{Network\,loss\;due\;to\;generation(MWh)}{(Annual\;generator\;output(MWh)\quad x \quad -1 \quad + \quad Network\,loss\;due\;to\;generation(MWh))}$$

100. For the wind generator example, the result of Equation 17 is: -0.0538 = 2,192 MWh / (42,924 MWh x -1 + 2,192 MWh).

101. Table 8 illustrates the results of two different generators' **TLRs** being converted to **TLFs**. The first generator increases losses within the network area, the second generator decreases losses.

Table 8: TLR and TLF summary for generators

Generator	TLR	TLF
Generator #1 (Wind generator example)	-5.38%	0.9489
Generator #2	5.00%	1.0526

Determining technical loss factors

102. Distributors should utilise the **TL**s calculated for each **network segment** as set out above when calculating **TLFs** for the **network study area**.

103. In summary, a distributor should attribute the **TLs**, in kWhs, to each load at each network level, accounting for the losses calculated for site specific loads and generation.

104. The **TLFs** that a distributor determines on its network need to be equated such that the total losses are accounted for.

105. Figure 4 below illustrates attribution of technical losses at each network segment to various loads, and the aggregation of those attributions.

Figure 4 - Attribution and aggregation of TL

	TL assigned to load connected at B	**TL** assigned to load connected at D	**TL** assigned to load connected at F
TL$_A$			
TL$_B$			
TL$_C$			
TL$_D$			
TL$_E$			
TL$_F$			
Sum of **TL** of relevant load connected	**TL** of load connected at B	**TL** of load connected at D	**TL** of load connected at F

106. The load connected at each segment of a distributor's network contributes to the losses in all segments upstream of the connection and the losses in each segment sum to the calculated **TL** values. This reconciliation of losses and allocation to demand within a **network study area** is shown in the spreadsheet. While it looks complex, it is relatively simple to achieve.

107. Once losses have been allocated in this manner, including accounting for any site specific connections, a distributor can calculate **TLFs** in a straight forward manner.

108. The calculation of **TLFs** provides a good basis for distributors to determine the HV and LV **RLFs** and potentially enables identification of **non-technical losses** that occur in a network if the **RL** is greater than the **TL** taking into account any uncertainty in the **TL** calculation. Without calculating **TLFs**, it is not possible for a distributor to estimate the possible extent of the any **non-technical loss**.

Determining reconciliation loss factors

109. When distributors have calculated **RLFs** appropriately, the result should (notwithstanding any unexpected changes in network configuration) be that average unaccounted for electricity (UFE) for the **network study area** is within +/-1 % over the course of any 12 month period.

110. Distributors should review **RLFs** every two years or if a 12 month UFE trend is outside of +/-1 %. If there is a significant change in network configuration and/or load within the two year period, the **RLFs** should be reviewed and updated.

111. The distributor's calculation of **RLF** should use 12 months of:

    (a) submission information provided by traders into the reconciliation process that has undergone the seven month revision[14] (as reported by the reconciliation manager to distributors in the GR-260[15] file or obtained directly from traders)

    (b) network input data (eg, Transpower data, embedded generator data, interconnection point data).

112. Distributors should determine **RLFs** for each **network segment** by calculating **technical losses** and apportioning **non-technical losses**.

Determining reconciliation loss factors by time periods

113. If the distributor desires, separate loss factors can be established for different seasons or periods such as day / night.

114. A distributor may wish to consider use of separate loss factors if system load factors are low and the calculation of loss factors by season or by day / night would result in enhanced price signalling at the retail level.

Distributor loss factor reporting

115. It is recommended that a distributor produces an annual loss factor methodology report. The purpose of the report is to aid transparency and understanding of the distributor's loss factor methodology. The report would state, for the following 1 April to 31 March year:

    (a) in relation to the distributor's chosen network disaggregation:

        (i) an overview of the distributor's entire network

        (ii) what **network study areas** were chosen and why

[14] As detailed in clause 15.27(1)(a) of the Code.

[15] For more detail on this file, refer to the reconciliation functional specification available from http://www.ea.govt.nz/industry/mo-service-providers/reconciliation-market-operation-service-provider/reconciliation-functional-specifications/

(iii) what **network segments** were chosen and why

(b) key assumptions made

(c) a table that, in relation to each active loss category code as recorded in the registry, the following:

(i) the **RLFs**, as recorded in the registry

(ii) the **TLF**

(iii) the **NTLF**

(iv) The last review date of the loss factors

(v) what the loss category code represents in terms of a voltage and/or customer class

(d) a description of the methodology.

116. A distributor should deliver a loss factor methodology report to the Authority by 1 April each year. This should be sent to marketoperations@ea.govt.nz

117. In the event that the Authority requests a distributor re-calculate their loss factors, the distributor should do so. In the event that the Authority requests a distributor reconsider their methodology for future calculations, the distributor should do so.

Appendix A Requirements of losses information on the registry

Code requirements

A.1 While care has been taken in the compilation of the below list, it should not be relied on by participants to identify their specific Code obligations. In the event of any discrepancy between these guidelines and the Code, the Code prevails.

A.2 Distributors must create loss category codes and loss factors and populate these into the registry loss factor table[16].

A.3 The registry will publish loss factors for each loss category code,[17] and these are only available to registry users.

A.4 Loss category codes on the registry may comprise a maximum of two loss factors per calendar month.[18]

A.5 Backdated changes to loss category codes and loss factors alter reconciliation and invoicing history. The Code requires forward notification be given for any new or changed loss category codes or loss factors.[19]

A.6 Unique loss factors must be determined for an ICP that connects a distributor's network to an embedded generating unit with a name plate rating of 10MW or more.[20]

A.7 The Code does not preclude distributors, at their discretion, calculating site-specific loss factors for points of connection other than those described in paragraph A.6.

A.8 Each distributor on either side of an interconnection point has a responsibility to populate the registry with loss factors for the NSP that connects to their network.

A.9 In the case of an embedded network gateway NSP or an interconnection point NSP, the reconciliation manager will only use[21] the loss factors provided by the distributor that initiated the connection. The distributor that initiated the connection of the NSP also has responsibility for providing the metering installation[22] and quantifying the conveyance of electricity.

Registry requirements

A.10 Registry functionality ensures that a distributor:

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[16] Clause 7(1)(e) of Schedule 11.1 of the Code.

[17] Clause 22(8) of Schedule 11.1 of the Code.

[18] Clause 22(2) of Schedule 11.1 of the Code.

[19] Clauses 21(3)–(5) and 22(5)–(7) of Schedule 11.1 of the Code.

[20] Clause 7(1)(f), (6), and (7) of Schedule 11.1 of the Code.

[21] The reconciliation manager uses the generation loss factor for interconnection points to adjust the flows out of the network of the distributor who initiated the connection.

[22] Clause 10.3(f) of the Code.

(a) cannot create a duplicate loss category code. However, different distributors can use the same loss category code

(b) can use duplicate loss factors as long as the loss category code is unique to the distributor.

A.11 Registry functionality requires that a loss category code may not exceed seven alphanumeric characters.

Appendix B Loss factor methodologies for embedded networks <1,000 ICP identifiers

Introduction

B.1 The following applies to embedded networks that have less than 1,000 ICP identifiers. Embedded networks with greater than 1,000 ICP identifiers should follow the main section of the guidelines.

B.2 An embedded network is a network that is connected directly to either:

(a) a local network; or

(b) another embedded network.

B.3 Embedded networks are considered separately in these guidelines because they:

(a) tend to have more homogeneous customer types than local networks

(b) can be reconciled by 'differencing'[23] which means that determining **non-technical losses** for a point of connection within the embedded network is fruitless[24]

(c) are usually physically small and electrically compact. It is believed that the **TL** within the network is small

(d) tend not to exist primarily for the purposes of operating a network; their core business is not the conveyance of electricity. Therefore, they often lack the resources to determine **TL**.

Methodology

B.4 In order to comply with these guidelines, distributors who own/operate an embedded network should determine loss factors by:

(a) considering what outcome is suitable for their embedded network

(b) to the extent that it does not conflict with paragraph (a), determine loss factors so that the net effect of all **RLFs** on a customer within the network is equivalent to a similar connection on the parent local network.

B.5 The formula to determine loss factors under paragraph (b) is:

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[23] This is where a dummy ICP is created on the network and the reconciliation manager derives the volume for that ICP by subtracted loss adjusted volumes from metered points of connection on the network from the metered volumes at the gate meter.

[24] Because the dummy ICP is 'claiming' the unmetered load and **non-technical loss** of the entire network.

Equation 18

$$\text{RLF} = \frac{\text{Comparable point of connection on local network RLF}}{\text{Gateway NSP RLF}}$$

B.6 For example, if a comparable point of connection on the local network has a **RLF** of 1.08 and the distributor for the local network has assigned a **RLF** of 1.06 to the gateway network supply point (NSP) of the embedded network, then the distributor for the embedded network should assign a **RLF** of 1.0189.

Documentation

B.7 To comply with these guidelines, distributors who own/operate an embedded network should:

(a) record the comparable point of connection **RLFs** that were used in the calculation process (in Equation 18), and the reasons why they were chosen as being comparable

(b) confirm and record that the gateway NSP **RLF** used in the calculation process (in Equation 18) is the same as the **RLF** specified in the AV130[25] file provided to the reconciliation manager

(c) have a documented process in place for identifying any changes by the parent network to either:

(i) the **RLFs** specified for the comparable points of connection; or

(ii) the **RLF** specified for the gateway NSP; and

(iii) make the records and documentation referred to in paragraphs (a), (b), and (c) available for review by the auditor appointed to conduct an audit required by clause 11.10 of the Code.

[25] For more detail on this file, refer to the reconciliation functional specification available from http://www.ea.govt.nz/industry/mo-service-providers/reconciliation-market-operation-service-provider/reconciliation-functional-specifications/

Appendix C Glossary of abbreviations and terms

Authority	Electricity Authority
Board	Electricity Authority Board
Code	Electricity Industry Participation Code 2010
guidelines	guidelines on the calculation and use of loss factors
GXP	grid exit point
HV	high voltage
LV	low voltage