Guidelines on the calculation and use of loss factors

14 February 2013

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	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.

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 **technical loss factors**

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

   (c) 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 upon 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.

[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)

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

Contents

Introduction

7. These Guidelines are recommended for use by distributors when calculating and publishing distribution loss factors.

8. These Guidelines are not mandatory.

9. 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.

10. Determining **technical loss factors** is highly recommended as a step in determining **reconciliation loss factors**.

11. These Guidelines are intended to be consistent with the Code and the Model Use of System Agreement (MUoSA) released for consultation on 11 August 2011[3]. Compliance with the MUoSA requires calculating loss factors in accordance with these Guidelines.

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

13. An example work book (Appendix D) has been produced as a partner document to these Guidelines. The work book contains:

    (a) equations for including **individually calculated customers** into the overall methodology for loss factor calculation

    (b) equations for calculating, summarising and allocating **technical loss**

    (c) equations for calculating **reconciliation loss**

    (d) equations for allocating **non-technical loss**

    (e) a template for reporting relevant results to the Authority.

14. A second work book (Appendix E) has also been produced that illustrates one possible methodology for calculating loss factors that apply to periods of less than a year (for example, summer and winter periods, or day and night periods).

3 Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/standardisation-muosa-and-proposed-code/

15. The version of these Guidelines and work books used during consultation can be found on the Authority's website at: http://www.ea.govt.nz/our-work/consultations/retail/loss-factor-methodologies

16. Where words appear in bold font, this indicates that the words are defined in paragraph 26 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.

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

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

Applicability of these Guidelines

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

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

21. These Guidelines do not apply to any other participants, including:

    (a) distributors who own/operate an islanded network (e.g. Chatham Islands, Stewart Island, Haast network)

    (b) the grid owner.

Purpose of these Guidelines

22. 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.

23. 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[4]. Distribution losses are believed to be 5.4% of the energy conveyed on distributors' networks in 2011[5]. Consumers face the cost of all losses, whatever the cause.

24. 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**.

25. The Authority intends to monitor the volume and percentage of **non-technical loss**. Inappropriately high **non-technical loss** would be discussed with the relevant participants with a view to minimisation, but could ultimately be investigated via an audit[6].

Defined terms

26. 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:

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

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[4] 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).

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

[6] Such as provided for under clause 12 of Schedule 15.1 of the Code.

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

To determine **LLFs** for distribution transformers where half hourly data is not available, refer to Appendix C.

(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 (refer to Figure 2 on page 17).

(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. Most distributors will 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”** 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 sum of **TL** and **non-technical loss**. It is 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

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

(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

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

(q) **"Utilisation factor" (UF)** means, in relation to a transformer, the ratio between its peak load (kVA) and its rated capacity (kVA)[7]. **UF** should 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%).

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

Introductory considerations

27. This section introduces:

    (a) the calculation methodology;

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

    (c) types and characteristics of the following **technical losses**:

        (i) **load loss**;

        (ii) **no load loss**; and

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

Overview of calculation methodology

28. The methodology used in these Guidelines is:

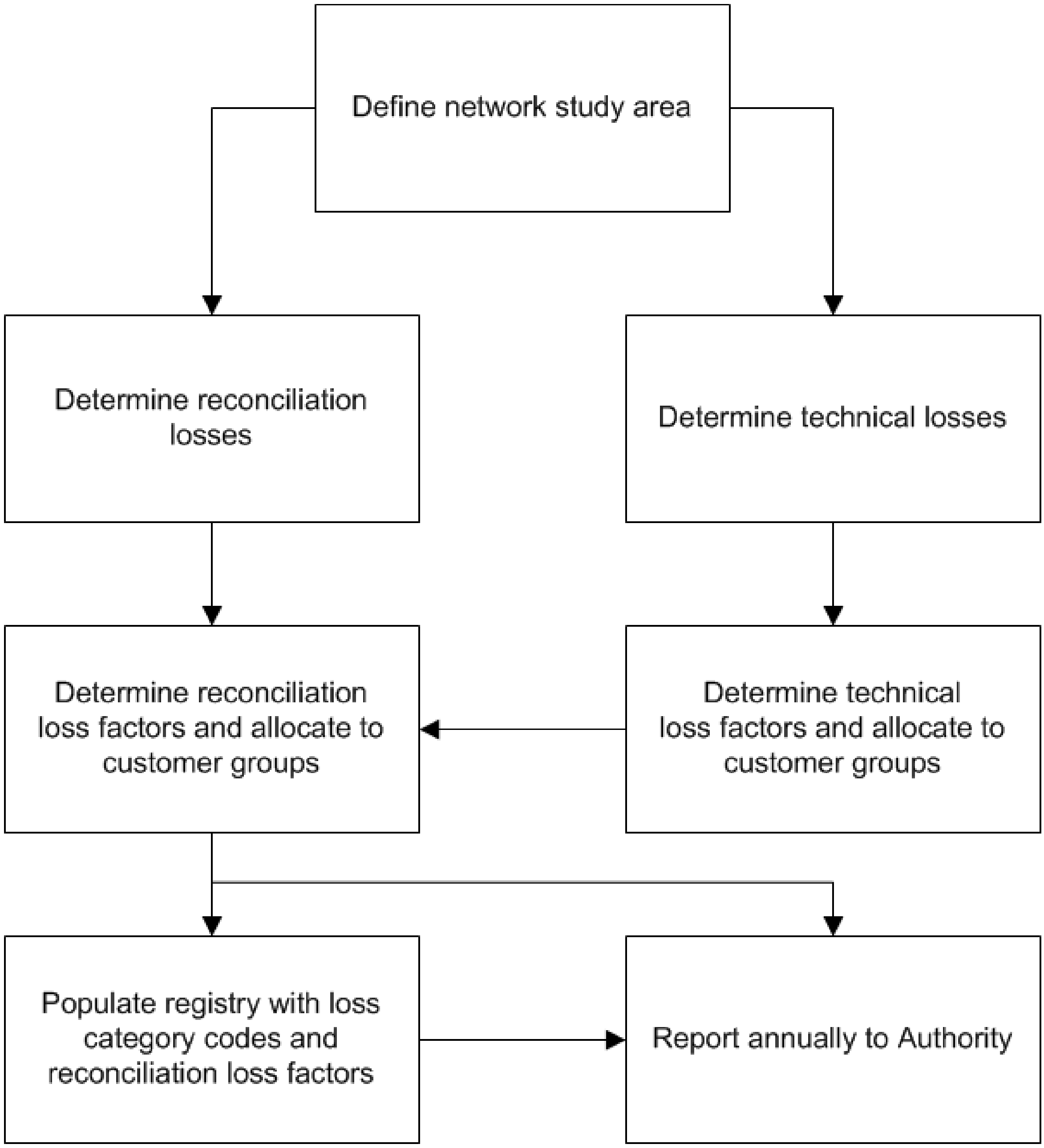
    (a) to determine **TLFs** for a **network study area** by disaggregating the **network study area** into **network segments** (including specific loss factors for individual customers)

    (b) to separately determine **RL**

    (c) to produce **RLFs** based on the **RL** and **TLFs** calculated for each **network segment** of the **network study area**.

29. Figure 1 below illustrates the flow of the key tasks involved for a distributor implementing these Guidelines.

Figure 1: Flowchart of key tasks



Disaggregating the network study area

30. It is necessary for a distributor to determine the appropriate degree of disaggregation of the **network study area**. The degree of disaggregation determines the number of loss factors.

31. 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 for each point of connection for each half hour period.

32. 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.

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

Technical losses

34. Determining **TL** is an important step in determining **RLFs**.

35. 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.

36. 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%.

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

Load loss

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

39. Distributors should 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

40. Distributors should 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.

41. Distributors should calculate annual **load loss** for each **network segment**.

No load loss

42. Distributors should 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**.

43. 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

44. 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.

45. For the purpose of calculating **RLFs**, the Authority recommends that submission information[8] is used after it has gone through the 7 month revision.

46. For **TLFs,** the Authority recommends the use of historical data that aligns with the period of information used for **RLFs** is recommended.

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

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

[8] 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/

Determining technical losses

49. This section explains the methodology that distributors should use to estimate **TLs**.

50. This section is broken down into the following sub-sections:

    (a) subtransmission network (≥33 kV) losses

    (b) zone substation transformer losses

    (c) HV network (22/11/6.6 kV) losses

    (d) distribution transformer losses

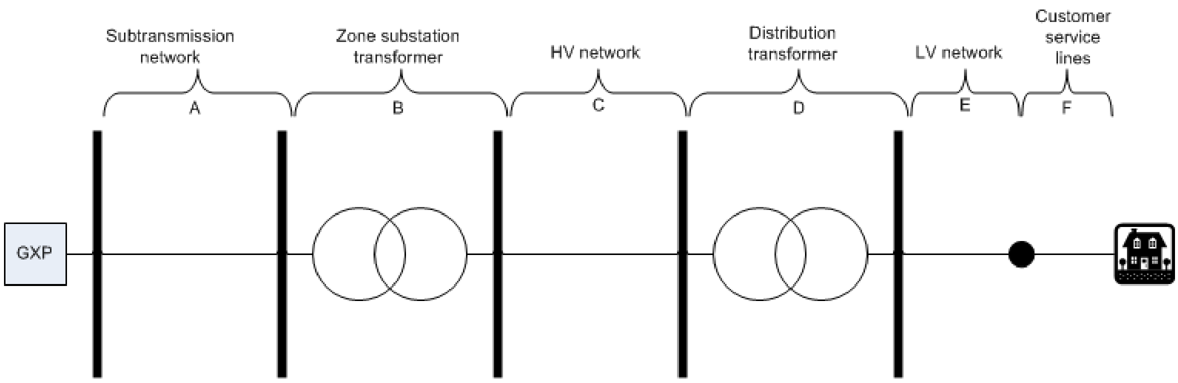
    (e) LV network losses

    (f) LV customer service line/cable losses

    (g) site specific losses (refer paragraph 89).

51. Figure 2 represents different **network segments** within the **network study area**.

Figure 2: Network segments



52. The network topology that should be used for all **TL** calculations should be based on normal operating configurations.

53. Throughout the rest of these Guidelines, each **network segment** in the **network study area** is referred to by the letter used in the topology diagram in Figure 2. For example, the **TL** for the zone substation transformer **network segment** at B is referred to as $\mathbf{TL}_B$.

54. Table 1 contains a summary of the method applied to calculate losses at each **network segment**.

Table 1: Technical loss calculation for each stage of the network

Losses applied to	Technical loss segment	Load losses	No load losses
Subtransmission network (≥33 kV)	TL_A	Using load flow software	N/A
Zone substation transformers	TL_B	For each transformer apply utilisation factor, zone substation transformer database.	Using manufacturer's data sheet and test sheets
HV network (22/11/6.6 kV)	TL_C	Using load flow software	N/A
Distribution transformers	TL_D	Using transformer count, utilisation factor, distribution transformer database	Using manufacturer's data sheet, test sheets and distribution transformer database
LV network	TL_E	Based on 5 sub-types	N/A
LV customer service lines	TL_F	Assumed value of 0.3% (refer paragraph 86)	N/A

Subtransmission (≥33 kV) network losses (TL_A)

55. Distributors should use load flow studies to determine the peak **load loss** in the subtransmission **network segment**. Peak **load loss** is calculated at peak demand for each subtransmission circuit.

56. Distributors should use 30 minute averaged zone substation data to determine the **LLF** for each subtransmission circuit. Where individual subtransmission circuit loading data is unavailable, distributors should calculate the **LLF** using GXP metered data applied to the subtransmission circuits.

57. Distributors should calculate annual **load loss** for each subtransmission circuit as per Equation 9 using its **LLF** as determined in paragraph 56.

58. Annual **technical loss** for the **network segment** is the sum of the annual **load losses** for each of the subtransmission circuits.

59. **TL_A** is used in the calculation of **TLFs** as described in paragraph 136.

Zone substation transformer losses (TL_B)

60. Distributors should calculate zone substation transformer peak **load loss** using peak demand for each transformer. Where zone substation transformers normally operate in parallel, distributors should use each transformer's normal share of peak total zone substation demand as the transformer peak demand.

61. Distributors should calculate **LLF** for each transformer using either 30 minute averaged transformer SCADA data or half hourly metered data. In the absence of either of these data sources, estimation will be required.

62. Distributors can obtain the **load loss** and **no load loss** for all zone substation transformers from manufacturer's data sheets. Distributors should calculate:

    (a) annual **load loss** for each zone substation transformer as per Equation 9

    (b) annual **no load loss** for each zone substation transformer as per Equation 10.

63. Annual **technical loss** for the **network segment** is the sum of the annual **load losses** and annual **no load losses** for each of the zone substation transformers.

64. $\mathbf{TL_B}$ is used in the calculation of **TLFs** as described in paragraph 136.

HV network (22/11/6.6 kV) losses (TL_C)

65. A distributor's HV network should be modelled, ideally using load flow software. Distributors should develop a model for each individual feeder, starting from the HV bus at its zone substation. Depending on the capability of the load flow software and availability of data, the model may also include:

    (a) two wire circuits

    (b) single wire earth return circuits with isolating transformers

    (c) spur lines.

66. If short and relatively small load spur lines are not modelled, then the load should be represented at the spur 'T' point.

67. Feeder models should include the losses incurred by voltage regulators, auto transformers and isolating transformers, but they need not include distribution transformer losses. Distribution transformers are not required to be modelled (refer to paragraphs 74-80), but the load connected to each transformer should be represented as a point load on the HV feeder, scaled to match the usual (non-contingency) peak demand on the feeder.

68. Distributors should use load flow studies to determine the peak **load loss** for each HV feeder in the **network segment** at each feeder's usual (non-contingency) peak demand.

69. If a distributor does not model all HV feeders, then it may select a range of representative feeders to model. The resulting losses can then be applied to similar unmodelled feeders.

70. Distributors should calculate **LLFs** for each feeder, preferably using load data from that feeder. Where load data is unavailable, distributors may calculate **LLFs** by using the **LLF** for another similar feeder or, failing that, the zone substation **LLF**.

71. Distributors should calculate annual **load loss** for each feeder as per Equation 9.

72. Annual **technical loss** for the **network segment** is the sum of the annual **load loss** of each HV feeder.

73. $\mathbf{TL_C}$ is used in the calculation of **TLFs** as described in paragraph 136.

Distribution transformer losses ($\mathbf{TL_D}$)

74. Distributors should calculate distribution transformer losses separately because they are not part of the HV load flow model.

75. Distributors can obtain the **no load loss** for all distribution transformers from manufacturer's data sheets. Distributors should calculate annual **no load loss** associated with distribution transformers as per Equation 10.

76. If a distributor has detailed information about loads for each distribution transformer, then it should use this information to determine **UF** and **LLF**[9]. In the absence of such data, distributors can obtain this information from a sample of distribution transformer load logging data. If a distributor does not have detailed information about loads for each distribution transformer, a sample of distribution transformer load logging data is considered to be the most reliable data available.

77. Distributors should calculate annual **load loss** associated with each sub-group of distribution transformer as per Equation 11.

78. The degree of disaggregation of transformers into sub-groups should be based upon available size, age and load profile data of the transformers, taking into account the perceived benefit for the effort.

[9] Refer to Appendix C for guidance on distribution transformer **loss load factors**.

Equation 11

Transformer load loss (kWh) = (Σ transformer load loss (kW) at max. rating) x UF^2 (pu) x LLF x TH(hrs)

79. Annual **technical loss** for the **network segment** is the sum of the annual **load loss** and annual **no load loss** of all distribution transformers.

80. $\mathbf{TL}_D$ is used in the calculation of **TLFs** as described in paragraph 136.

LV network losses (TL_E)

81. Due to the variety and number of LV network circuits, the variable level of LV network loading and general lack of modelling data, the Authority recommends that distributors use the methodology in this section.

82. Table 2 shows five different sub-types of LV networks and the associated estimation of loss performance. Distributors should model the LV network based on these five categories, using the most appropriate sub-type possible based on the description of the LV network and transformer size.

Table 2: LV network sub-types

Sub-type	Description	Transformer size *kVA*	Percentage kWh loss of the LV network *Conductor loss/(conductor loss + consumption)*	Mean load on the transformer *% of transformer rating*	Maximum load on the transformer *% of transformer rating*
CBD	Mix of retail, business (mainly office space) and some residential (in apartment blocks)	1000	0.61%	22%	76%
High density	Mainly residential (apartments) and some retail	300	0.34%	32%	85%
Medium density	Typical suburban houses	200	1.22%	44%	94%
Low density	Small number of large houses on large sections	100	0.51%	47%	105%
Rural	Single house plus a shed fed off a single transformer	15	0.30%[10]	9%	63%

Hyland McQueen Ltd, LV losses modelling 17 February 2011

83. Appendix F contains a report from Hyland McQueen Limited. This details the methodology and assumptions used in producing Table 2.

84. Distributors should consider the applicability of the percentage loss of the LV network in Table 2 for each LV network sub-type. Where differences are significant, distributors should make the appropriate adjustments. However, if a distributor is considering adjustment due to the average kWh usage per consumer on the LV network sub-type, then it is also be important to take into account the number of consumers connected to each LV network sub-type (as explained in Appendix F).

85. Appendix D provides distributors with an example of how to calculate an annual **TL** in kWh for **network segments** E and F.

[10] Loss measured below numeric resolution of model. For a loss in this circumstance to not register in the model analysis, the percentage loss must be between 0% and 0.6%. The value in the table represents the mid-point as the best estimate in this circumstance.

86. Note that the modelling undertaken for the five sub-types does not include the losses in customer service lines. Whilst the losses in customer service lines is a few percent at peak load time, given the low **load factor** of most customers (approximately 10% to 15%), the annual loss from customer service lines are considered to be between 0.2% to 0.4%. For the purposes of these Guidelines losses of 0.3% are assumed.

87. For embedded generators with a nameplate capacity of less than 10kW, the distributor should use an **RLF** equal to the **TLF** determined for the consumption at that location. For larger generators connected to a distributor's network, refer to paragraphs 91-93.

88. **TL_E** is used in the calculation of **TLFs** as described in paragraph 136.

Site specific technical losses

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

90. 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.

91. For embedded generators of 10kW or more, but less than 1MW, the distributor will 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**.

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

93. 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.[11]

94. 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.

95. The Authority recommends that distributors calculate site specific loss factors for any interconnection points[12] involving their network. Accordingly, the Authority recommends

[11] clause 7(6) of schedule 11.1.

[12] As defined in clause 1.1 of the Code

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.

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

97. 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.

98. 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

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

100. 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 12

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

101. 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.

102. A distributor should calculate a site specific **TLF** from the results of paragraph 101 per Equation 13.

Equation 13

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

Site specific loss factor based on incremental impact

103. 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 is often required to provide an adequate network connection[13].

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

105. 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.

106. 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).

107. 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.

108. Network losses are dependent on the size of both background network load and generation. In order to accommodate this variability, the distributor will 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 3: Scenario matrix

	Site specific generator

[13] An incremental based loss calculation is useful to help determine the economically sized network by balancing capitalised energy loss cost against network capacity cost.

Background load	None	Low	Med	High
Low				
Med				
High				

109. ‘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.

110. 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.

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

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

113. 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.

114. To help make the units clearer and to be consistent with the companion workbook, 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 1 year).

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

116. 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.

117. 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.

118. 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 4: 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**

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

120. Total losses with and without generation are calculated by multiplying Table 4 by either Table 5, Table 6 or Table 7 depending on the correlation scenario chosen.

121. 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 5 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 5.

Table 5: 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***

122. Table 6 below shows high positive correlation where the generator is managed to match its output to the network load.

Table 6: 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***

123. Table 7 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 7: 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***

124. Continuing with the wind generator example and using Table 4 and Table 5, Table 8 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 8: 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 14: Calculation of the sum of losses under generation scenarios

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

125. Equation 14 is: 9,533 MWh = 2,160 MWh + 5,767 MWh + 1,606 MWh

126. This calculation shows that the generator is expected to cause additional network losses (i.e. 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 15: Calculation of network loss due to generation

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

127. Equation 15 is: 2,192 MWh = 9,533 MWh – 7,341 MWh

Equation 16: Calculation of time weighted annual generator output

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

128. The purpose of Equation 16 is to sum the annual output of the generator. For the wind generator above, the inputs to Equation 16 are shown in Table 9.

Table 9: Generation output scenarios

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

129. Using Table 9, the result of Equation 16 is: 42,924 MWh = 5,256 MWh + 26,280 MWh + 11,388 MWh

130. 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 17: Calculation of TLF for generator

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

131. If a generator reduced the losses in a network then the “Network loss due to generation” in Equation 17 would be negative and **TLF** will be greater than 1.0.

132. For the wind generator example, the result of Equation 17 is: 0.9489 = 1 + (2,192 / 42,924 x -1)

133. The result of Equation 17 is then used as the **TLF** for the **ICC**.

Equation 18: Calculation of TLR for generator

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

134. For the wind generator example, the result of Equation 18 is: -0.0538 = 2,192 MWh / (42,924 MWh x -1 + 2,192 MWh).

135. Table 10 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 10: 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

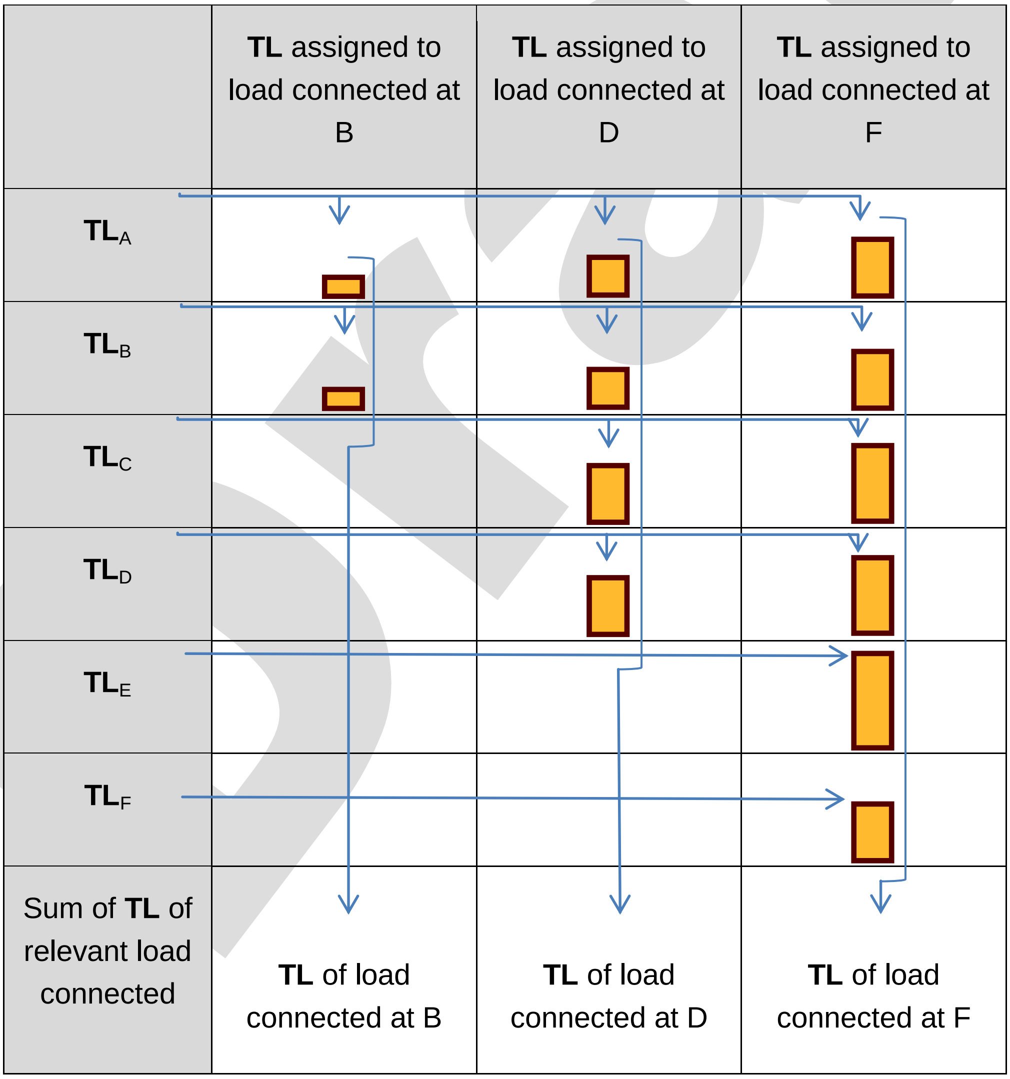
136. Distributors should utilise the **TL**s calculated for each **network segment** as set out above when calculating **TLFs** for the **network study area**. This is illustrated in the example spreadsheet (refer Appendix D).

137. 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.

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

139. Figure 3 below illustrates attribution of technical losses at each network segment to various loads, and the aggregation of those attributions.

Figure 3 - Attribution and aggregation of TL



140. 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.

141. 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.

142. 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

143. 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 close to zero over the course of any 12 month period.

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

    (a) submission information into the reconciliation process that has undergone either the 7 month revision[14] (as reported by the reconciliation manager to distributors in the GR-260[15] file)

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

145. Distributors should determine **RLFs** for each **network segment,** general loads and **ICC,** by calculating **technical losses** and apportioning **non-technical losses**.

146. The companion work book (Appendix D) also provides an illustration of how distributors should calculate and allocate **non-technical losses** to loads within the **network study area**.

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/

Determining reconciliation loss factors by time periods

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

148. 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.

149. An additional companion work book (Appendix E) is provided which provides an illustration of how to break out the general load HV and LV loss factors by day / night or by summer / winter. This work book assists distributors to understand how the **loss** varies on a seasonal (monthly) basis or day / night basis and how the resultant mix of **load loss** and **no-load loss** varies during the year.

150. Instructions for completion of the work book are listed on one of the tabs. The network load data is used as an allocator to spread the **load loss** over each half hour. Note that distributors should remove site specific load from the system load data before pasting into the sheet.

151. If a distributor has not completed a full technical loss study for the relevant network area and there are no site specific loads, or only some relatively small site specific loads, then the distributor may estimate the ratio of HV loss to LV loss using empirical means and make an adjustment to the estimation for the proportion of HV metered general consumption to total general consumption.

Distributor loss factor reporting

152. 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

      (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 **technical loss** and **reconciliation loss**

      (iii) the **non-technical loss** implicit from the **technical loss** and **reconciliation loss;**

      (iv) the **TLR** and **RLR**

      (v) the **non-technical loss** ratio implicit from the **TLR** and **RLR**

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

   (d) a description of the methodology and datasets used.

153. 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

154. The Authority may refer concerns about any distributor's loss factor methodology to the Loss Factor Review Panel (LFRP), which will provide advice to the Authority. 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 upon 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].

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 ICP that connects to their network.

A.9 However, the reconciliation manager will only use[21] the loss factors provided by the distributor that initiated the connection. The distributor that initiated the connection 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 cannot create a duplicate loss category code. However, different distributors can use the same loss category code.

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

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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 Clauses 7(1)(f), 7(6) and 7(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

Appendix B Loss factor methodologies for embedded networks

Introduction

B.1 An embedded network is a network that is connected directly to either:

B.1.1 a local network; or

B.1.2 another embedded network.

B.2 Embedded networks are considered separately in these Guidelines because they:

B.2.1 tend to have more homogeneous customer types than local networks

B.2.2 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]

B.2.3 are usually physically small and electrically compact. It is believed that the **TL** within the network is small

B.2.4 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.3 In order to comply with these Guidelines, distributors who own/operate an embedded network should determine loss factors by:

B.3.1 considering what outcome is suitable for their embedded network

B.3.2 to the extent that it does not conflict with B.3.1, 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.4 The formula to determine loss factors under B.3.2 is:

Equation 19

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

B.5 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.

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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.

Documentation

B.6 In order to comply with these Guidelines, distributors who own/operate an embedded network should:

B.6.1 record the comparable point of connection **RLFs** that were used in the calculation process (in Equation 19), and the reasons why they were chosen as being comparable

B.6.2 confirm and record that the gateway NSP **RLF** used in the calculation process (in Equation 19) is the same as the **RLF** specified in the AV130[25] file provided to the reconciliation manager

B.6.3 have a documented process in place for identifying any changes by the parent network to either:

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

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

(c) make the records and documentation referred to in paragraphs B.6.1 to B.6.3 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 Loss load factors for distribution transformers

C.1 In July 1996, the Transformer Capitalisation Working Party produced a guide for the Electricity Engineers' Association entitled *Purchase and Operating Costs of Transformers*. The written guide and associated spreadsheet covered both distribution and zone substation transformers.

C.2 Page 3 of *Purchase and Operating Costs of Transformers* states that the **LLF** of transformers is not easy to obtain as the value depends on the loading pattern. There are two ways by which **LLFs** are commonly derived:

Equation 20: Loss Load Factor method 1

$$LLF = k \times LF + (1-k) \times LF^2$$

Where k means proportioning multiplier in the LLF equation

Where 0 < k < 1 and k is normally between 0.05 and 0.3

Equation 21: Loss Load Factor method 2

$$LLF = LF^{PC}$$

Where PC means power coefficient

Where 1< PC < 2 and if unknown use PC = 1.912

C.3 Table 11 below provides some guidance on the typical **LLFs** for various sizes of distribution transformer for various types of load (residential, commercial and industrial).

Table 11: Loss Load Factors for Distribution Transformers

PARAMETER	DISTRIBUTION TRANSFORMERS			
Rating (kVA)	30	300	300	750
Date of Manufacture	1995	1995	1995	1995
Voltage Transformation (kV)	11/.415	11/.415	11/.415	11/.415
Applicable Rating Range (kVA)	10-50	50-500	100-500	500-1500
Location	Rural	Urban	Any	Any
Customers Supplied	Residential	Residential	Commercial	Industrial
Output Voltage, per unit	1.00	1.00	1.00	1.00
No-Load Power Loss (kW)	0.070	0.475	0.475	0.910
Load Power Loss (kW)	0.665	3.050	3.050	7.335
Transformer Utilisation Factor	0.50	0.80	0.70	0.80
Temperature Correction Factor	0.90	0.96	0.93	0.95
Diversity Factor for Distribution	0.70	0.81	0.81	0.63
Diversity Factor for Transmission	0.50	0.50	0.50	0.50
Load Factor	30%	38%	22%	45%
Loss Load Factor	10%	16%	9%	28%

Appendix D Companion work book #1

D.1 A work book has been produced to assist in the understanding and application of these Guidelines.

D.2 This work book is entitled *Companion work book to the loss factor methodology guidelines*, and is available from http://www.ea.govt.nz/our-work/consultations/retail/loss-factor-methodologies.

Appendix E Companion work book #2

E.1 A work book has been produced to assist in the understanding and application of reconciliation loss factors by time period.

E.2 This work book is entitled *Companion workbook for reconciliation loss factors by time period*, and is available from http://www.ea.govt.nz/our-work/consultations/retail/loss-factor-methodologies.

Appendix F Hyland McQueen report

F.1 Below is a copy of the report completed by Hyland McQueen

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Mr Callum McLean
Adviser Retail Operations
Electricity Authority
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25 March 2011

Dear Callum,

LV LOSSES MODELLING

In accordance with both your instructions and the directions of the Loss Factor Review Panel we have pleasure in presenting this letter report on low voltage (LV) distribution network losses for typical LV distributor configurations.

Summary

We have considered the average network losses on 5 typical mains distribution types as described in Table 1 following and as further described in this letter.

Network	Description	Transformer Size
CBD	Mix of retail, business (mainly office space) and some residential (in apartment blocks).	1000 kVA
High Density	Mainly residential (apartments) and some retail	300 kVA
Medium Density	Typical suburban houses	200 kVA
Low Density	Small number of large houses on large sections	100 kVA
Rural	Single house plus a shed fed off a single transformer	15 kVA

Table 1: Summary description of mains distribution types.

The losses resulting from loadings on these networks have been assessed are are presented as percentage loss ratios in Table 2 following.

Network	Percentage kWh loss of the LV mains distribution [conductor loss /(conductor loss + consumption)]	Mean load on transformer (percent of Tx. rating)	Maximum load on transformer (percent of Tx. rating)	Voltage quality (on last node) **/b**
CBD	0.61%	22%	76%	98%
High Density	0.34%	32%	85%	99%
Medium Density	1.22%	44%	94%	96%
Low Density	0.51%	47%	105%	98%
Rural	0.30% /a	9%	63%	100%
a/ Loss measured below numeric resolution of model. For a loss in this circumstance to not register in the model analysis, the percentage loss must be between 0% and 0.6%. The value in the table represents the midpoint as the best estimate in this circumstance. b/ Voltage quality measured on the end node (furthest from the transformer) as the 5th percentile of the distribution of ordered half-hourly averaged voltages at that network node and expressed as a percentage of source voltage.				

Table 2: Network analysis summary results

The network and load circumstances, means of analysis, and observations on the results are detailed within the main body of this letter.

Objective

The objective of this work is set out in our letter of 25 September 2010 and as further modified and extended by our letter of 18 January 2011. In brief, we have modified our low voltage network analysis software to calculate network losses on low voltage (LV) distributor networks to estimate the loss factors on such networks. Following discussions with the Loss Factor Review Panel, we have created 5 example networks and calculated the network losses and loss factors in each.

Main Discussion

Example Network Selection

Five LV mains networks have been promoted as generally representative of the types of LV networks in place across the country. These example networks are set out in Table 3 and further discussed following.

			Average Energy as kWh per day					
LV Network Category	**Description**	**Transformer**	**Residential**	**Retail**	**Office**	**Load Spacing**	**No. Circuits**	
CBD	50% retail, 30% business office and 20% residential apartments	1000 kVA	17 kWh/day ea. in 9 unit groups	50 kWh/day in single units	38 kWh/day ea. in 4 unit groups	15 m	5	1
High Density	10% retail and 90% residential in multiple residences with close spacing	300 kVA	25 kWh/day in single residences & 25 kWh/day ea. in 4 unit groups	50 kWh/day in single units		15m	4	1
Medium Density	100% residential as suburban houses	200 kVA	25 kWh/day in single residences			20 m	2	19
Low Density	100% residential – larger houses	100 kVA	40 kWh/day in single residences			40 m	2	19
Rural	1 house and 1 shed	15 kVA	30 kWh/day in single residences			40 m	1	

Table 3: Description of example networks

- The percentage customer mix is based on number of connections - not proportion of total energy.
- The number of circuits and conductor sizes are our best estimate based on the general experience of both ourselves and the Loss Factor Review Panel. Please note that we assume a 'typical network' is for a network already in place. A new installation would probably use 120 sq.mm Al conductor as a minimum conductor size but existing installations commonly have smaller conductor sizes, which is why we have selected 95 sq.mm as being typical for the medium density network case.

CBD

- As discussed with the Loss Factor Review Panel – large high rises would usually have their own transformer or transformers, so our typical CBD network, in terms of LV distribution, is for 'main-street' loads that would consist of single and up to four-story buildings.
- The modelled network has been set out in 5 identical underground circuits.
- These circuits are arranged retail; retail; offices; apartments; retail; retail; offices; retail; retail; offices; apartments. This gives a connection mix of 55% retail, 27% offices and 18% residential (close to the design target of 50; 30; 20).
- Retail implies a single retail connection with a mean energy use of 50 kWh/day. Based on load data for this type of customer class, we assume a between customer standard deviation of 44 kWh/day. [26]
- Offices are assumed to be connected in groups of 4 (*viz* – four offices per building connection). Offices are assumed to have a mean load of 38 kWh/day with a between customer standard deviation of 40 kWh/day for each office.
- Apartments are assumed to be connected in groups of 9 per building connection with a mean load of 17 kWh/day and with a between customer standard deviation of 9 kWh/day.
- The network distribution cables assumed are underground 4-core Al 185mm sq XLPE.
- The loading is arranged to suit a 1000 kVA transformer installation.

High Density

- We assume a mix of 90% residential and 10% retail loads.
- The network is arranged as underground in 4 identical circuits.
- We have assumed a mix of single residential and 'flat blocks' with 4 residential loads in a single building connection in a ratio of approximately 3:2 (single residential to flat blocks).
- Each residential load assumes a mean load of 25 kWh/day with a between customer standard deviation of 14 kWh/day
- The network distribution cables assumed are 120mm sq Al 4-core XLPE
- The loading is arranged to suit a 300 kVA transformer installation.

Medium Density

- We assume all residential load class in single house connections.
- Distribution in overhead network connections arranged as two circuits - each as illustrated in Figure 1 following.
- House spacing's are 20m apart and with road crossings at 20m
- Each residential connection assumes a mean load of 25 kWh/day with a between customer standard deviation of 14 kWh/day.
- The overhead conductor modelled is 3-phase Cu 37/0.072 (approximately 96 sq.mm) + neutral of Cu 19/0.072: Road crossings with Cu 19/0.072
- The loading is arranged to suit a 200 kVA transformer installation.

[26] Based on time of use metering data made available to us.

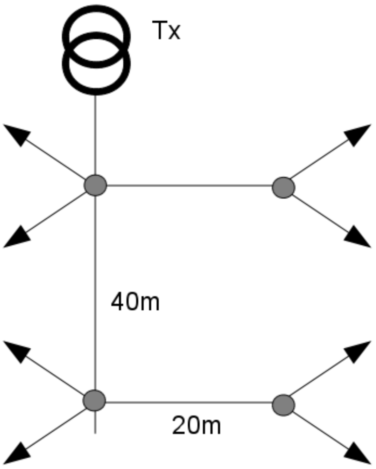

Figure 1: Medium density network configuration

Low Density

- Assume all residential load class in single house connections.
- Distribution in overhead network connections arranged as two circuits - each as illustrated in Figure 2 following.
- House spacing's are 40m apart with road crossings at 20m
- Each residential connection assumes a mean load of 40 kWh/day with a between customer standard deviation of 14 kWh/day. That is - a 'high use' house load for each connection.
- The overhead conductor modelled is 3-phase Cu 37/0.072 (approximately 96mm sq) + neutral of Cu 19/0.072: Road crossings with Cu 19/0.072 [same as the medium density case]
- The loading is arranged to suit a 100 kVA transformer installation.

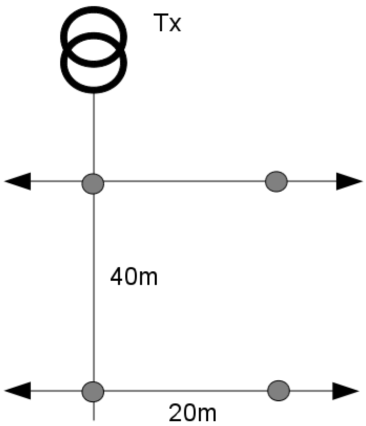

Figure 2: Low density network configuration

Rural

- Single house + shed
- Assumes a residential load of 30 kWh/day with a between customer standard deviation of 14 kWh/day.

- The shed load is assumed at 4 kWh/day (as a sub-main off the house)
- The distributor conductor is assumed to be 40m of 35mm sq Cu neutral screen cable strung overhead.
- Off a 15 kVA single phase dedicated transformer.

Customer Load Types

Customer class load behaviour is based on observations from customer energy records in the Dunedin area. Translation of the network analysis results to other areas with possibly lower average annual energy consumption is discussed in later section of this letter. The following charts of Figure 3 gives the distribution of between customer average energy per day for four of the largest customer classes of interest to this work as derived from the Dunedin energy data.

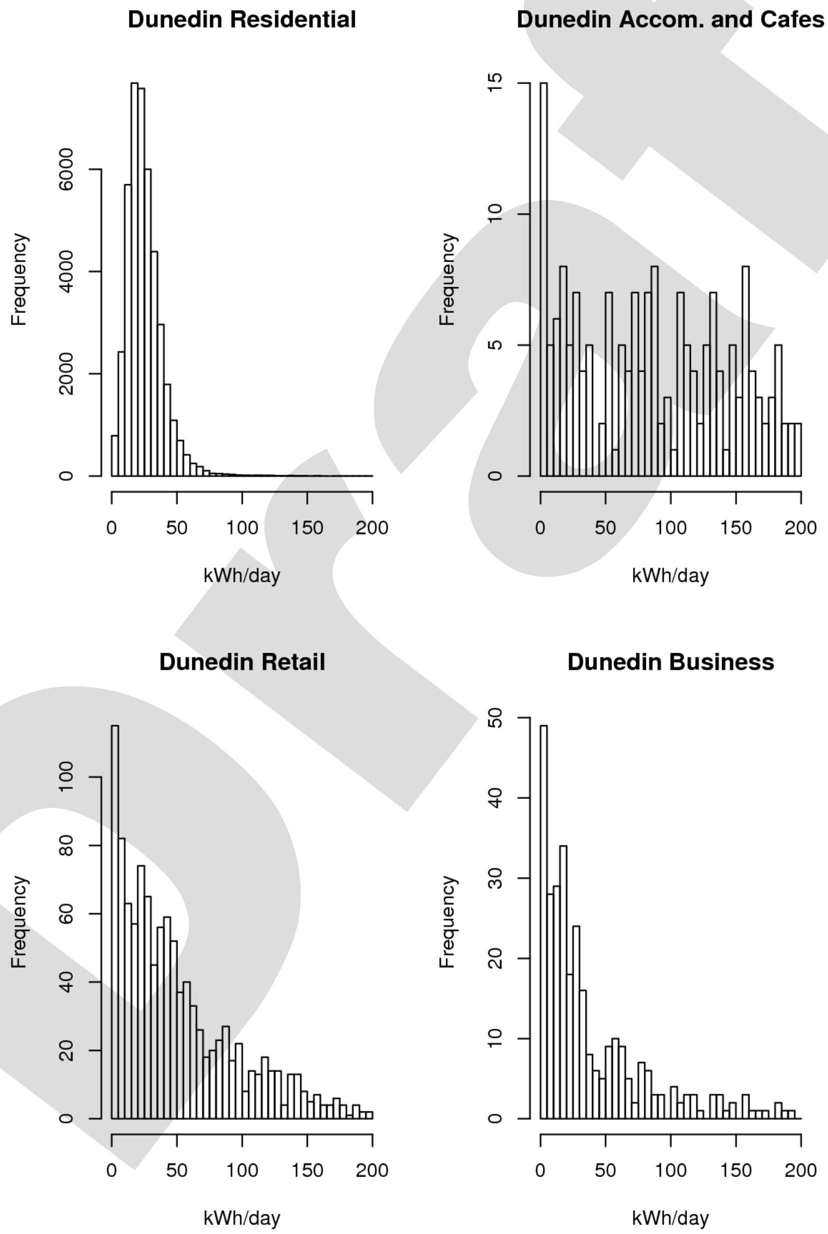

Figure 3: Distribution of average daily energy (kWhs) for customers in different customer classes

Please note that the accommodation and cafés load class is based on relatively few records, as evident in the y-axis scale for this chart, so the observed distribution must be treated with some caution and noting that this class would also cover hotels with large energy use (and probably dedicated transformers). In our representative networks, only residential, retail and business load types are applied.

<u>Residential Class:</u>
The average energy per connection is (approximately) 25 kWh/day (= 9,125 kWh/year). The variability of the average daily energy between customers of the residential class is taken from the standard deviation of the distribution and is approximately 14 kWh/day. We make the following assumptions:

- For CBD residential, this will be mostly apartments that are (generally) smaller, with smaller numbers of occupants per apartment and (sometimes) shared central heating. In essence, we treat CBD residential as a sub-class of the residential class. We make the assumption that each CBD residential load consumes only 2/3 of the average residential energy consumption or 17 kWh/day and has a similarly scaled standard deviation, giving a between customer variability of 9 kWh/day.
- For high density residential, this will be a mix of individual houses and blocks of flats. For these types of residential loads we simply assume the average energy consumption for the residential load class or 25 kWh/day with a between customer standard deviation of 14 kWh/day.
- Medium density residential – we again assume the average energy consumption for the residential load class or 25 kWh/day with a between customer standard deviation of 14 kWh/day.
- Low density – this type of network is to typify larger houses so we take an energy consumption close to the 75th percentile of the load-per-day distribution – or approximately 40 kWh/day but assume the same variance behaviour as the general population of residential customers *i.e.* a between customer standard deviation of 14 kWh/day.
- Rural – based on the residential between-customer energy distribution for 15 kVA transformers (discussed later), we make an estimate of 30 kWh/day as being the typical mean energy use per day (= 120% of the average residential) with a between customer standard deviation of 14 kWh/day.

<u>Retail Class</u>
The average energy per day from our Dunedin data set is 50 kWh/day for this customer class and we use this value in our network models. Also based on the Dunedin data for this customer class we use a between customer standard deviation of 44 kWh/day.

<u>Business Class</u>
The average energy per day from our Dunedin data set is 38 kWh/day for this customer class and we assume this value in our network models. Also based on the Dunedin data for this customer class we use a between customer standard deviation of 40 kWh/day.

<u>Variation in Energy Behaviour with Transformer Size</u>
As we are applying our example networks off different transformer sizes it is prudent to check that the customer average energy consumption is not characterised differently between different sized networks.

The following histograms are derived from Dunedin residential annual energy consumption metering data for customers off different sized transformers and are expressed in kWh/day:

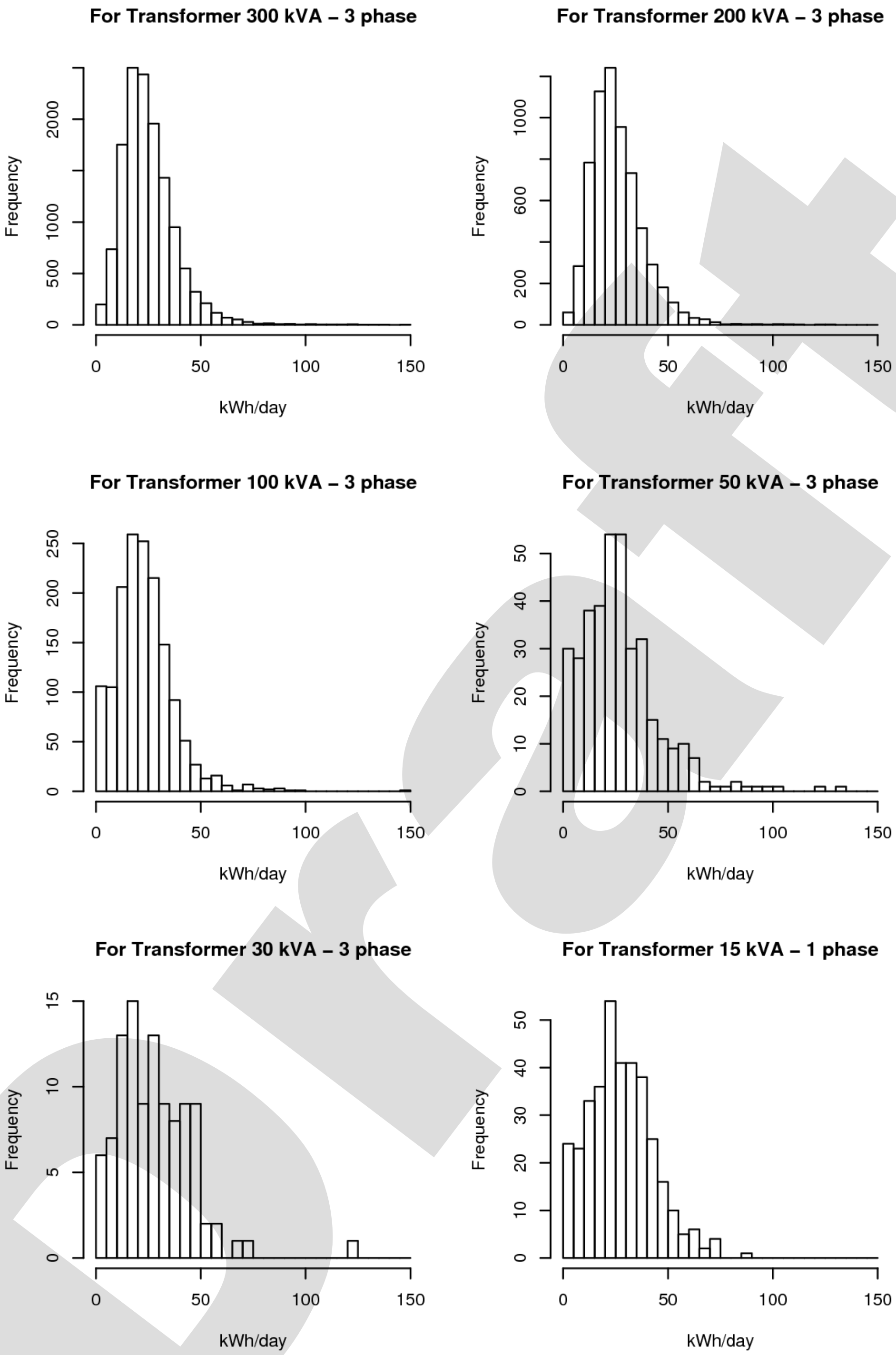

Figure 4: Distribution of average energy per day by customers connected to different sized transformers

In the larger transformer sizes the distribution of between customer average energy per day is relatively unchanged so it appears reasonable to use the residential average energy per day within the network models for the larger sized transformers (50 kVA and greater).

In the smaller transformer sizes, however, the distribution of between customer average energy per day appears shifted to the right suggesting we should use a slightly higher average energy per day figure in the models if we are after typical values. For this reason we selected a higher average energy per day for the customers on the example rural network, as noted previously.

Analysis Method
The analysis method used applies an LV network analysis tool (RiNO) built to assess delivered voltage quality in LV networks. This tool has been modified by us to also calculate and report the network losses. The model uses a repeated sampling technique (Monte-Carlo analysis) that applies loads at the nodes of the LV network being examined then calculates the subsequent network currents, voltage drops and losses. Loads are modelled in half-hourly intervals over a day and the model 'runs' 1000 simulated days to derive the distribution of delivered voltage at each point in the network. The underlying load simulation method varies between load types dependant on the particular characteristics of that load type.

The key features of the analysis techniques applied to describe the time-wise behaviour of the connected loads are:

Aspect	Purpose
Load types are selectable	We use residential, retail and business load model types in the representative networks. Each load model type applies both internal and external parameters. Internal parameters are derived through study of the measured time series load behaviour for the load types and includes parameters like duty cycle and temperature dependence. External parameters are entered to describe know circumstances for the actual loads (like average daily energy consumption)
Requires average daily energy consumption to be identified	This is derived from a study of metering data by ICPs grouped into the appropriate customer classes.
Optional entry of standard deviation of the between - customer average daily energy consumption	Entered where the actual average daily energy consumption for the particular connection is not known but where the population behaviour of energy consumption of the customer class is known. This parameter accounts for the uncertainty in knowing the actual average daily energy consumption of a customer connected at a particular point in the network.
After diversity daily load profile (for residential loads)	Used to describe the after diversity daily load cycling for residential loads. For non-residential load types a weekday and weekend duty cycle is described based on observation of the load type behaviour.
Temperature data for the network region	While average daily energy use is not well correlated with daily temperature – there is still a correlation which the model accounts for. This is

Aspect	Purpose
	also the mechanism by which the particular daily energy is statistically selected.
Loads are described by Gamma distributions	This derives from the mathematical analysis of load behaviour.

The analysis methodology is further described in the following IEEE papers:

- McQueen, Hyland & Watson, "Monte Carlo simulation of residential electricity demand for forecasting maximum demand on distribution networks", IEEE Trans. PES, January 2004.
- McQueen, Hyland & Watson, "Application of a Monte Carlo simulation method for predicting voltage regulation in low voltage networks", IEEE Power Engineering Society, July 2004

<u>Model Limitations</u>

The known and key limitations of the applied load models and analysis method are:

1. The currents at the network loads are calculated based on the simulated power drawn by the loads at any point in time and where nominal voltage is assumed at each node for the calculation of the load current. The error from this assumption is small where the true voltage regulation in the network is small (*i.e.* less than 10%) which was the case in all the example networks analysed.
2. The network model assumes a full occupancy rate over the network being modelled. The main error from this assumption occurs where the model is used on networks with known low average occupancy rates – like resort towns or holiday batches. In the particular case of estimating loss ratios, the effect of this error will be small as the loss is being expressed as a ratio of the energy throughput.
3. The model method becomes less accurate with low numbers of connections, as the effect of statistical averaging diminishes, and with larger proportions of non-residential load types, as the non-residential load types show greater variance in energy use and daily load cycle between loads of the same class – that is the loads are more individually unique and difficult to characterise. In the particular case of estimating loss ratios, the effect of this error will be reduced as we are attempting to characterise a "typical" network rather than replicate the voltage quality or maximum demand behaviour of a particular network.

Analysis Results

The losses resulting from loadings on the example networks described have been assessed are presented as percentage loss ratios in Table 4 below. [27]

Network	Percentage kWh loss of the LV mains distribution [conductor loss /(conductor loss + consumption)]	Mean load on transformer (percent of Tx. rating)	Maximum load on transformer (percent of Tx. rating)	Voltage quality (on last node) **/b**
CBD	0.61%	22%	76%	98%
High Density	0.34%	32%	85%	99%
Medium Density	1.22%	44%	94%	96%
Low Density	0.51%	47%	105%	98%
Rural	0.30% /a	9%	63%	100%
a/ Loss measured below numeric resolution of model. For a loss in this circumstance to not register in the model analysis, the percentage loss must be between 0% and 0.6%. The value in the table represents the midpoint as the best estimate in this circumstance. b/ Voltage quality measured on the end node (furthest from the transformer) as the 5th percentile of the distribution of ordered half-hourly averaged voltages at that network node and expressed as a percentage of source voltage.				

Table 4: Summary of network analysis results

While the percentage loss ratios appear low, it must be remembered that these are the average network losses as a percentage of throughput. As conductor losses rise as a square of the conductor current, a disproportionate amount of the loss will occur at the time of the highest network loads, but on an average basis the percentage loss ratio will be reduced by the large periods of lower network load. This is especially the case with the CBD loads where load at night is substantially reduced (and this is accounted in the duty cycle ascribed to these customer class load types).

It is difficult to see any trend in the results presented in Table 4. The main issue appears to be that there are too many variables including customer class, customer mix, network topology, conductor type, conductor size, load density and delivered voltage quality, few of which are consistent between the different networks making it difficult to determine what the key drivers of the different losses are.

Transfer and Scalability

An important question to consider is how the results of the analysis undertaken might be transferred to other parts of the country where average daily energy consumption is different and where transformer utilisation is different to the cases described.

<u>Effect of Reduced Average Daily Consumption</u>

We have considered the effect of changed average customer load expressed in the models in kWh/day. The kWh/day load used for the “average” residential household, as derived from the Dunedin metering data, was 25 kWh/day or approximately 9,000 kWh per annum. It is known, however, that annual loads in the north of New Zealand are lower; in the order of 7,000 kWh per annum.

[27] The results presented in the table are the average of 5 'runs' of the LV analysis model.

For the medium density network example – that represents an 'average' residential suburban networks – we reduced the average daily consumption by 7/9 to 19 kWh/day and reduced the between customer standard deviation by a proportionate amount (14 to 11). This resulted in the following comparison with the base case as presented in Table 5 following:

Network	Percentage kWh loss of the LV mains distribution [conductor loss/(conductor loss + consumption)]	Mean load on transformer (percent of Tx. rating)	Maximum load on transformer (percent of Tx. rating)
Medium Density	1.2%	43%	90%
Medium Density Reduced	0.9%	33%	70%

[illegible] educed average daily energy consumption

[illegible] sses reduced in direct proportion to the square of the average current reduction (as conductor loss goes as a square of the conductor current) we would expect a reduction in loss from 1.2% to 0.7% (=$1.2 \times (19/25)^2$) The model value of 0.9% indicates the square law reduction accounts for the majority of the observed difference and would be useful as a first approximation in adjusting the calculated percentage losses between different areas of the country.

<u>Transformer Loading</u>

The transformer percentage loadings provided with the network loss ratios in Table 4 may vary to the average loadings on the network for which LV network losses are to be assessed. The effect of this has been assessed by halving the load in the medium density case by removing one of the two circuits and rerunning the analysis. The comparison is provided in Table 6 following.

Network	Percentage kWh loss of the LV mains distribution [conductor loss/(conductor loss + consumption)]	Mean load on transformer (percent of Tx. rating)	Maximum load on transformer (percent of Tx. rating)
Medium Density	1.22%	43%	90%
Medium Density – Half Load	1.19%	22%	51%

Table 6: Effect of reduced transformer loading

The percentage loss ratio reduced from 1.22% to 1.19% - a relative reduction of 2.5% compared to a load reduction of 50%. The degree to which the transformer is loaded (and this would apply to networks with low occupancy rates) would therefore not appear to be a significant issue and, considering all other sources of error, may not worth adjusting for.

<u>Voltage Quality</u>
Mains distribution design is commonly a compromise between the delivered voltage quality to the customers and the capital cost of the LV network, where the designer seeks to place the smallest conductors - and therefore minimise capital cost - while also meeting a voltage quality standard.

In deriving the typical networks presented here, we have focused on loading up the networks to match transformer loadings that are typical in our experience rather than designing to a voltage quality standard as the latter is difficult to express and is known to vary between different utility providers as there is no common standard for assessing the delivered voltage of a mains distribution design. The loadings and number of connections applied in our representative networks results is relatively good delivered voltage quality, which we consider not atypical as the number of voltage complaints in most networks is extremely small compared to the total number of connections.

Where voltage quality in the particular network is a known issue then the loss factors should be increased in a square law relationship to the assessed decrease in voltage quality compared to our representative networks. [28]

In Conclusion

We thank the Electricity Authority for the opportunity to undertake this work and we thank the Loss Factor Review Panel for its assistance and guidance in this work. We look forward to receiving any questions or comments back from the Electricity Authority and/or the Loss Factor Review Panel.

Yours faithfully,

PR Hyland for and on behalf of Hyland McQueen Limited

[28] Voltage drop in a network segment increases in proportion to the current but losses increase in proportion to the square of the current.