EVALUATION OF DISTRIBUTION LOSS FACTORS 2008-2009

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TABLE OF CONTENTS

1 Introduction

The National Electricity Rules require that Distribution Network Service Providers (DNSPs) obtain the approval of the Australian Energy Regulator (AER) for Distribution Loss Factors (DLFs) for the DNSPs network.

This report nominates the DLFs for Integral Energy's electrical distribution network for the 2008/2009 financial year. It also outlines the application of the methodology and assumptions and base data used for the calculation of the loss factors.

Integral Energy's methodology for calculation of distribution loss factors is attached to this submission. The methodology is based on the National Electricity Rules, as well as taking account of the Guideline issued by the Independent Regulatory Tribunal prior to this responsibility transferring to AER ("Assessment and Approval Process of Distribution Loss Factors proposed by DNSPs", dated November 2007).

The methodology used in this report has been altered in some areas compared to that used by Integral Energy in previous years.

Historically, Integral Energy has used a hierarchical approach to determine the distribution loss factors. In general, the method used to calculate series energy losses has been to first calculate the loss on the relevant part of the system under peak load conditions using Integral Energy's load flow package (DINIS), and then calculate the associated energy losses, by use of an appropriate Loss Load Factor (LLF) as:

$$\text{Series Energy Losses (kWh)} = \text{peak losses (kW)} \times 8760 \text{ hours} \times \text{LLF}$$

The LLF is the ratio between the instantaneous losses incurred at peak load and the average instantaneous losses over a year. It is based on the square of the load and can be expressed as follows:

$$LLF = \sum_{n=1}^{35040} (\text{load}_n{}^2 / \text{peak load}^2) / 35{,}040$$

where:	35,040	= the number of 15 minute load recordings in one year
	load_n	= the 15 minute average load in the nth 15 minute period.
	peak load	= the highest 15 minute average load in the year

LLFs were traditionally calculated for all Bulk Supply Points (BSP's), major generators, transmission substations, zone substations and major customers. These LLF's were evaluated using metering data where available at each location, or alternatively, SCADA data where metering data was not available.

Peak losses were then modelled using location specific demand forecasts for the coming year. These forecasts were used to model the transmission (132kV), sub-transmission (66kV and 33kV) and distribution (22kV and 11kV) networks in order to maximise the accuracy in the loss estimation at each level of the network.

Within substations, transformer no-load losses can be calculated from manufacturer's data where available as:

$$\text{Shunt Energy losses (kWh)} = \text{shunt losses (kW)} \times 8760 \text{ hours}$$

Since these losses are independent of the transformer loading, no LLF is applied.

The new methodology, which is explained further in the attached methodology document, proposes an improvement to the process whereby the entire transmission (132kV) and sub-transmission (33/66kV) networks, including all Transmission Substations (TS) and Zone Substations (ZS) are modelled in an appropriate software package and load flow simulations run for every 15 minute period for the year 2008-09 using forecast data as the basis for the calculations. From these simulations, network losses are aggregated for each tier of the network down to, but not including, the distribution networks at 11/22kV and 400/230V.

Distribution network losses for the 11/22kV systems are calculated in the traditional way by carrying out load flow calculations on each ZS network at peak loading, determining a LLF as described above, and thereby estimating the losses from that process. The losses in the LV network are then taken to be the residual losses calculated as the difference in the total projected input energy, including that from Bulk Supply Points (BSP) and embedded generators, and the total billed data in the network. .

As required by the Rules, the proposed DLFs are "forward looking" and use both demand and energy forecast data as provided by Integral Energy's Forecasting Section for the 2008/09 fiscal year.

2 Summary of Results

Network Level	2008/2009		2007/2008		2006/2007	
	Effective Section Loss Factor %	Cumulative Loss Factor %	Effective Section Loss Factor %	Cumulative Loss Factor %	Effective Section Loss Factor %	Cumulative Loss Factor %
132 kV Network	0.40%	0.40%	0.59%	0.59%	0.62%	0.62%
Transmission Substation	0.42%	0.91%	0.45%	1.04%	0.45%	1.06%
Subtransmission Network	0.63%	1.57%	0.58%	1.83%	0.58%	1.83%
Zone Substation	0.52%	1.76%	0.58%	2.22%	0.61%	2.26%
High Voltage Distribution Network	0.93%	2.82%	0.98%	3.22%	1.19%	3.48%
Distribution Substation	2.60%	5.89%	2.31%	6.39%	2.47%	6.86%
Low Voltage Distribution Network	2.23%	8.55%	1.99%	8.55%	1.64%	8.43%

Table 1 - Generic Loss Factors

Notes:

1. All % loss factors quoted in the above table are given as the % of energy delivered at that level of the network, whether to customers at that level, or to lower levels.
2. In this study section loss factors do not add numerically to give cumulative loss factors due to the effects of compounding and network configuration.
3. An allowance for theft and non-technical losses of 0.5% of total sales has been made.

An examination of both the current (2007/08) and the proposed generic 2008/09 DLFs shows that there is no significant difference between the results. However, there are some small reductions in the DLFs for the 132kV Network, Transmission Substations, Zone Substations and the High Voltage Distribution Network. These changes are considered to be a combination of improved load flow techniques and Loss Load Factor (LLF) data, as well as the factoring in of capital works, particularly at the Transmission and Zone Substation level.

In addition, and in accordance with the National Electricity Rules, all customers with a consumption of greater than 40GWh and/or 10MW demand have had site specific Loss Factors calculated. Embedded Generators with a peak output of greater than 10MW have also had Loss Factors calculated. The methodology for the calculation of these DLFs is based on the difference in losses in the network between the conditions where the generator is operating and not operating over an annual cycle, relative to the energy sent out by the generator over the same period.

3 Reconciliation of Forecast and Actual Losses

As required by the Rules, a reconciliation of forecast and actual losses has been carried out. This involved taking the complete billing data set for 2006/07 and applying the estimated DLFs for that year to the data to determine the expected system losses. A comparison between the actual losses as calculated from the billing data and the losses calculated by using the DLFs at each tier of the network is shown in Table 2 below.

The detailed reconciliation of forecast and actual losses are provided in Appendix B.

Financial Year	Forecast Loss kWh	Actual Loss kWh	Difference kWh	Energy Distributed kWh	Forecast error as % of Energy Distributed
2005/06	1,020,888,259	978,559,243	42,329,016	17,204,938,460	0.25%
2006/07	1,062,802,864	922,626,278	52,888,560	17,457,846,045	0.303%

Table 2 – Reconciliation of Forecast to Actual Losses

Note that financial year 2006/07 is the last complete set of available billing data.

4 General comments on changes to DLFs

General comments driving changes to DLFs are summarised below:

- There has been an improvement in the system load flow modelling since the previous Loss Study calculations for the 2007/08 year. This includes a refinement of the load flow models, and load flow calculations for each 15 minute metering interval throughout the year.
- Care has been taken to ensure that the transmission network was modelled in the configuration that is most representative of the way in which the system is generally operated in practice.
- Load flow models for the 2008/09 year were executed with the network configured according to current capital program commitments.
- Substantial effort has been put in to returning out-of-service or failed capacitors at Transmission Substations to service and to installing capacitor banks on the 11kV busbar at Zone and Transmission Substations. Consequently, a level of static reactive support has been modelled in the load flow calculations. However, the magnitude of this support is less than the maximum available. Instead, the status of each capacitor has been estimated by considering the time weighted average reactive support at each location.

5 Application of the Methodology

5.1 Treatment of Theft

This study has identified theft as a separate line item and has taken a value of 0.50% of total sales (as recommended by the DLF Working Group) and applied this to the calculations. It has been assumed that all theft occurs at low voltage and the overall theft apportionment is therefore allocated to the low voltage network. Consequently, this equates to 0.76% of low voltage sales.

5.2 Site Specific DLFs

Site specific DLFs for embedded generators >10MW have been calculated. These are located at Maribeni (formerly Sithe Guildford) and Appin and Tower Collieries.

Location specific loss factors were calculated for a total of 23 significant customer connection points. The factors were calculated using the same methodology as the general loss calculations; using forecast metering data from the 2006/07 year to determine the 15 minute average line losses using a load flow calculation.

Note that location specific loss factors were not calculated for Sydney Water at Prospect, Burrawang Pumps and Australian Paper (Bomaderry), as in previous years, as their consumption did not meet the requirement of >40GWh energy and/or 10MW demand in the 2006/2007 year.

In most cases the major customers shared upstream network assets with other general Integral Energy Network customers. As noted previously, the energy losses for these shared assets were calculated and allocated to the loads in proportion to the energy delivered to each load by each asset through a linear estimate of the load flow solution at each metering interval. The location specific loss factors were then calculated using the total energy losses attributable to a particular load divided by the energy delivered to that load. These quantities were then subtracted from the overall network pool, which was used to calculate the general Loss Factors.

5.3 132kV Lines

Integral Energy's 132kV network supplies transmission substations, 132/11kV zone substations and 132kV customers. Forecast metering data from the 2006/07 year were used to determine the 15 minute average line losses using a load flow calculation. This metering data was normalised to account for both the forecast 2008/09 peak demand and the forecast energy consumption from the network.

The 132kV line losses were then accrued from the load flow calculations conducted for each 15 minute metering interval. In the case of site specific 132kV customers, the 132kV line losses attributable to that customer were calculated from a linear estimation of the load flow solution, at each time interval.

5.4 Transmission Substations

Transformer series losses were calculated by applying the forecast 2008/2009 load data to the network load flow model. The transformer losses were then accrued from those obtained in each 15 minute metering interval.

Actual shunt losses were used for 60% of transmission substations. The average shunt losses for the known transformers, as a percentage of rating, were applied to the remainder.

5.5 Sub-transmission Lines

The sub-transmission line series losses were also calculated by applying the forecast 2008/2009 load data to the network load flow model. The line series losses were then accrued from those obtained at this level of the network in each 15 minute metering interval.

5.6 Zone Substations

As in the case of transmission substations, the transformer series losses were calculated by applying the forecast 2008/2009 load data to the network load flow model. The transformer losses were then accrued from the losses in each metering interval.

Actual shunt losses were used for 67% of transmission substations. The average shunt losses for the known transformers, as a percentage of rating, were applied to the remainder.

5.7 Medium Voltage Lines (11kV, 22kV)

The medium voltage peak distribution line losses for the whole distribution network were modelled by applying the forecast 2008/09 peak demands to the DINIS load flow model for each of the Zone Substation networks. The losses for each Zone Substation network were then calculated using the 2006/2007 LLF for that zone substation, applied to the peak line losses of feeders supplied from the particular substation.

In cases where a site specific customer was supplied by a medium voltage distribution feeder, the losses attributable to the general tariff customers were first determined by calculating the LLF, while excluding the site specific customer from the load flow model. The calculation was then repeated using the site specific customer's own LLF and a load flow model which excluded the general tariff customers.

5.8 Distribution Substations

Losses incurred within distribution substations were assessed by using an average load and generic transformer characteristics due to the large number (28,585) of distribution transformers in the Integral Energy network. The numbers of each size of transformer were determined from Integral Energy's Asset Database (Ellipse) as at March 2007.

Transformers of 100kVA or greater are generally fitted with Maximum Demand Indicators (MDIs) and so maximum loadings can be monitored. The latest MDI reading for each individual transformer was used to determine an average utilisation for each transformer category, or rating. For those transformers with no corresponding MDI data, a lower utilisation of 50% was assumed.

Transformer full load loss values ranged from 1.5% of rating for the smallest transformers down to 0.9% for the largest. Shunt losses ranged from 0.5% of rating for smaller units down to 0.25% for the larger ones. A LLF ranging from 0.250 to 0.306 has also been used for the distribution transformers as this is representative of the average LLF for the whole of the Integral Energy network.

5.9 Low Voltage Lines

Due to the lack of load information and modelling data it is not possible to model LV network losses directly. Instead, losses were assessed using an assessment of energy purchases less energy sales, theft and other losses.

To determine LV network losses, total losses were first calculated by subtracting energy purchases from energy sales. All other calculated network losses, including theft, were then subtracted from total losses to give the LV network losses.