

**EFFECT OF CONDUCTOR SIZE ON THE TOTAL COST OF  
ELECTRICITY DISTRIBUTION FEEDERS IN  
SOUTH AFRICAN ELECTRIFICATION**

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# ABSTRACT

**Thesis Title:** Effect of conductor size on the total cost of electricity distribution feeders in South African electrification

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There is an optimum conductor size that minimises the lifetime cost of domestic electrification networks. The lifetime cost consists of the initial capital cost and ongoing running cost. Technical load losses are an important running cost and consideration for conductor size optimisation.

Traditional conductor size optimisation methods base technical load loss costs on upstream generation and network costs. These loss costing methods assume that consumers behave as constant power loads. The impact of conductor voltage drops on changes in consumer energy consumption and demand and hence changes in utility bulk purchase cost and sales revenue are ignored. Traditional load loss calculation methods do not adequately describe the stochastic nature of individual consumer loads. In low-voltage domestic networks traditional methods may account for less than 25% of the actual lifetime running cost due to load losses and conductor voltage drop. It is shown that the results of traditional conductor size optimisation methods are severely compromised.

A new method has been developed for the optimisation of conductor size in radial distribution networks supplying stochastic domestic consumers. MV and LV networks can be analysed in the same study to prevent sub-optimisation. Statistical time-of-use load loss and voltage drop calculations consider the stochastic nature of individual consumers. Lifetime running costs include conductor load loss costs and conductor voltage drop costs. The simplifications and assumptions used in the new method have been tested via sensitivity analysis on South African domestic electrification networks. The accuracy of the load loss and voltage drop calculations used in the method have been tested via Monte Carlo simulation using South African domestic load research data.

The new method is suitable for implementation in network analysis software for use in practical planning and design functions in utilities.

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# ABBREVIATIONS

<b>AC</b>	Alternating Current
<b>ACSR</b>	Aluminium Conductor Steel Reinforced
<b>ADD</b>	After Diversity Demand
<b>ADMD</b>	After Diversity Maximum Demand
<b>BEST</b>	Basic Electricity Support Tariff
<b>CAD</b>	Computer Aided Design
<b>CSI</b>	Climatic Severity Index
<b>DETS</b>	De Energised Tap Switch
<b>DG</b>	Distributed Generation
<b>DSM</b>	Demand Side Management
<b>HV</b>	High Voltage (in South Africa > 33kV)
<b>LF</b>	Load Factor
<b>LLF</b>	Loss Load Factor
<b>LR</b>	Load Research
<b>LV</b>	Low Voltage (in South Africa $\leq$ 1kV)
<b>MV</b>	Medium Voltage (in South Africa > 1kV $\leq$ 33kV)
<b>NPV</b>	Net Present Value
<b>OLTC</b>	On-Load Tap Changing
<b>PF</b>	Power Factor
<b>QOS</b>	Quality Of Supply
<b>ROI</b>	Return On Investment
<b>WEPS</b>	Wholesale Electricity Pricing System

# GLOSSARY

<b>ADD</b>	The average load per consumer over a particular time period, such as a month.
<b>ADMD</b>	The average load per consumer at the instant of overall maximum demand. It depends on the size of the group of consumers, and in South Africa is expressed in amps or kVA for 1000 consumers.
<b>Beta distribution</b>	Statistical distribution bounded between 0 and 1 and defined by two shape factors $\alpha$ and $\beta$ .
<b>Confidence Level</b>	The probability that a particular value of a random variable will not be exceeded.
<b>Customer Tariff</b>	Retail tariff paid by utility customers and is usually comprised of energy charges.
<b>Diversity</b>	The sum of the non-coincident maximum demands of individual consumers is usually less than the coincident system maximum demand, and is referred to as diversity.
<b>Empirical</b>	A method or solution based on observation or experiment, and not a theoretical derivation.
<b>Herman beta algorithm</b>	The Herman Beta algorithm transforms a beta distribution of load currents (at the instant of maximum demand) to a distribution of consumer voltages using a beta probability density function.
<b>Heuristic</b>	An iterative computer-based solution that proceeds by trial and error.
<b>Homogeneous population</b>	A population in which each consumer exhibits the trends of the population. There are no sub-groups of consumers (e.g. with and without hot water cylinders) within a homogeneous population.
<b>Load Factor</b>	Ratio of the average power demand to the maximum power demand over a time period.
<b>Loss Load Factor</b>	Ratio of the average load loss power demand to the maximum load loss power demand over a time period.
<b>MV Lateral</b>	A spur line off the MV primary line (see MV primary). The MV lateral line conductor sizes will usually be smaller than that of the MV primary line it is supplied by. In South Africa MV lateral lines are also referred to as "tee-offs". The MV lateral line may be three phase, single phase or SWER.
<b>MV Primary</b>	That part of a MV distribution feeder supplying the bulk of the load and may interconnect with surrounding distribution feeders to allow load transfer during network outages. In South Africa MV primary lines are also referred to as "backbone". The MV primary line is usually three phase and supplies MV lateral lines (see MV lateral).

<b>Risk</b>	The complement of the confidence level i.e. a 95% confidence level corresponds to a 5% risk.
<b>Stochastic</b>	A quantity that is statistical in nature, and characterised by a sequence of random variables.
<b>Utility Loss Tariff</b>	Energy and demand charges used by a utility for the costing of technical losses. The Utility Loss Tariff may be the retail tariff paid by the utility for bulk power purchases from generation/transmission.

# **1. INTRODUCTION**

This chapter introduces the research problem, the optimisation of conductor size in South African rural domestic electrification. A summary of the South African electrification program outlines the South African domestic consumer backlog and some of the challenges of electrification. General distribution planning and design philosophies are discussed. Possible problems with the present South African electrification network planning and design philosophy and tools are identified, leading to the formulation of the research hypothesis.

## **1.1 SOUTH AFRICAN ELECTRIFICATION**

The term electrification has different meanings in different countries. In South Africa "electrification" is the provision of access of households to electricity. A consequence of electrification is electrical supplies to non-domestic loads such as schools, clinics, shops and water pumping loads. Electrification network planning and design methods also need to consider non-domestic loads.

The following relevant information and observations are provided by Gaunt [2003] in an analysis of electrification technology and processes to meet economic and social objectives in Southern Africa:

- Over 3 million new domestic households in South Africa were connected during the past decade.
- The percentage households electrified are 80% and 46% in urban and rural areas respectively. Approximately 36% of South African households are not yet electrified and of these households, 71% are in rural areas.
- Politicians have stated goals of achieving universal access by 2012, and this is expected to cost at least R10 billion (initial capital cost only).
- Electrification is performed for social (poverty alleviation), not economic, reasons. The minimisation of cost is essential to maximise the sustainability of the electrification program. Standards (such as voltage quality criterion) need to be carefully assessed to

ensure that they are compatible with the objectives of the electrification program. Reduced standards (such as increased voltage variation) should be considered if there is a net cost savings and the reduction in standards does not diminish the delivery of the benefit (poverty alleviation).

The majority (71%) of the South African electrification backlog is in rural areas [Gaunt, 2003]. The cost to service rural areas is higher than urban areas due to sparse rural settlement characteristics. Enhanced planning and design methods have the potential to assist electrification by reducing the cost of electrification. This research focuses on rural domestic electrification, which is expected to dominate South African distribution network expansion for the next 10 years.

South African rural domestic settlement characteristics vary significantly. Some settlements are characterised by formal rural villages with an orderly urban type layout of homes and roads, but energy consumption is low and villages are relatively small and isolated from one another. In other settlements, such as many in rural Kwa-Zulu Natal, there is no formal village layout and customers are sparsely located in relation to the small areas of land they cultivate as subsistence farmers. Variations in consumer energy consumption and settlement characteristics hamper the standardisation of planning and design approaches.

## 1.2 DISTRIBUTION NETWORK PLANNING AND DESIGN

General distribution network planning and design has been described by many including SABS 0150 [1983, subsequently withdrawn], Gaunt [1988], Lakervi and Holmes [1995], Willis [1997].

Carter-Brown [2003] provides an overview of distribution MV and LV network planning and design in Eskom Distribution (Eskom Distribution is the distribution division of Eskom, the South African national electricity utility responsible for bulk generation, bulk transmission and distribution in areas not supplied by local municipalities). Network planning and design are different. Network planning involves decision making in an environment of uncertainty, where there may be several scenarios, and data is limited. By comparison network design is relatively well defined, with reasonably detailed network and load data such that the uncertainty is significantly reduced. For example, network planning may involve the sizing of a MV network to supply potential load in a geographic area, where individual customer requirements are not known. Network design involves the subsequent connection of each

individual customer, where each customer's load requirements are reasonably well understood. Network planning is a logical prerequisite to network design.

The following are typical network planning outputs [Carter-Brown, 2003]:

- MV voltage levels (11kV, 22kV etc ).
- MV configuration (loop versus radial).
- MV and LV technologies (three phase, phase-to-phase, SWER, single phase and bi-phase as discussed further in section 2.1).
- MV and LV primary line routings and conductor sizes.

For the purposes of this research, more detailed outputs/analysis is considered to be network design.

The preferred requirements for the planning and design of South African networks supplying LV domestic consumers are contained in the NRS 034-1 [1999]. NRS 034-1 [1999] divides the factors influencing network planning and design into three categories:

- Fixed parameters over which the designer has no control (statutory requirements, existing services, existing residential layout).
- Factors over which the designer has limited control (consumer loads via effects due to load limiting and demand side management).
- Factors over which the designer should exercise control (initial capital and lifetime cost, network layout, cable/conductor sizes, voltage drop limits, quality of supply).

A systematic approach to distribution planning and design decreases costs [Khator and Leung, 1997]. When planning and designing distribution networks to supply a forecasted load requirement the primary focus should be the minimisation of lifetime costs within the constraints of regulatory and utility standards (the fixed parameters" referred to by the NRS 034-1 [1999]) [Willis, 1997]. Preferred alternatives may vary significantly from the optimal (minimum lifetime cost) solution if only initial capital costs are used for the evaluation of different alternatives [IEC 287-3-2, 1995].

The network lifetime costs include the following main components [Willis, 1997; Paciornik et al, 2003]:

- Installation cost (capital investment cost and labour).

- **Operations, administrative and maintenance costs.** These arise as a result of equipment maintenance, equipment monitoring and equipment failure due to either age or a specific abuse of the system such as lightning strikes, vandalism, theft etc.
- **The cost of energy purchases.** Energy purchases for a typical utility might be purchased from a generation/transmission company, or the cost of the local distribution generation. Included in the energy purchase costs are electrical losses cost (as a result of the power dissipated in the electrical network resistances) and non-technical losses costs (these include theft and poor metering).
- **Reinforcement and upgrading costs to meet future load requirements.**

The main regulatory and utility network standards influencing distribution network planning and design are [Willis, 1997; Paciornik et al, 2003]:

- **Maximum thermal limits of transformers and conductors.**
- **Maximum and minimum voltage limits.**
- **Minimum reliability levels.**
- **Voltage waveform quality (voltage dips, unbalance, flicker and harmonics) also need to be considered, but are usually only considered in specific applications where large single phase or non-linear loads are to be supplied.**

Sellick [1999] differentiates between "requirements" and "constraints". Thermal limits are considered a constraint that should not be violated as this may result in utility equipment damage. Voltage, QOS and reliability limits can be interpreted as requirements. The network may be able to operate outside of these limits without immediate equipment damage. The effects will be reflected as increased lifetime cost due to a reduction in equipment lifespan and increased customer dissatisfaction (fines, customer compensation and tariffs linked to QOS and reliability as experienced by customers).

Agoris and Argiropoulos [1994] analyse distribution MV planning philosophies for the electrification of developing countries:

- *"distribution-network planning models which have already been applied in other countries must be thoroughly analyzed before applying any part of them in the electrification planning of a developing rural area, because the local conditions may diverge considerably from those which prevail in the countries used as examples."* [Agoris and Argiropoulos, 1994].

- *"Since the funds of developing countries are always limited, special effort must be given to the design of a reliable low-cost network, by taking into account equipment and construction costs, the exploitation costs, as well as the costs of the future modifications."* [Agoris and Argiropoulos, 1994]. Developing countries cannot afford to make mistakes by adopting non-optimal planning practices that ultimately result in increased cost.
- The cost of rural electrification is significantly affected by the distribution planning philosophy. Agoris and Argiropoulos [1994] note that the application of planning philosophies suitable for developed countries typically results in a capital cost of six times that of the approach suitable for a developing country. The inclusion of loss costs reduces the lifetime cost difference to a factor of four.
- Initially, long (>100km) MV feeders with single phase laterals result in least cost for rural electrification. These "long" MV feeders are voltage limited. Voltage drop requirements are addressed via shunt compensation and line voltage regulators. As loads increase and the network expands, the optimal planning philosophy is to convert single phase laterals to three phase, increase distribution voltages (where practical and the existing voltage is not optimal) and reduce feeder lengths via additional HV/MV injections [Agoris and Argiropoulos, 1994].

Based on the finding of Agoris and Argiropoulos [1994], the following conclusions can be made for South African rural domestic electrification:

- Planning and design models need to account for the specific characteristics of the customer (load magnitude, load density) and network (equipment characteristics) in developing countries.
- Network planning and design needs to take network lifetime costs into consideration.
- The distribution planning and design philosophy must be appropriate for the particular application, especially rural electrification. Different philosophies are required for developed and developing countries.
- Distribution planning and design tools and methods should be applicable to unbalanced, voltage limited feeders supplying small dispersed loads. The effects of voltage compensating equipment need to be included in network analysis.

The selection of conductor size has a large impact on network voltage drop [SABS 0150, 1983]. South African domestic electrification networks are voltage limited. Conductor size has a significant impact on the network lifetime capital and technical loss costs [Sellick, 1999].

### **1.3 PHILOSOPHY OF SOUTH AFRICAN ELECTRIFICATION NETWORK PLANNING AND DESIGN**

The South African electrification program is focused on reducing the backlog of un-electrified homes in urban and rural areas. The principle of the discounting of future costs as a present value is recommended by the NRS 034-1 [1999] for the evaluation of lifetime costs. The evaluation of lifetime costs, as recommended by the NRS 034-1 [1999], is not implemented in Eskom Distribution.

In Eskom Distribution, the designer's brief is to produce a minimum initial (year 1) capital cost design that meets basic voltage and thermal standards, using standardised network technologies and components (poles, transformers, conductors, insulators, meters etc). Network planning and design philosophies and tools do not consider lifetime costs. Furthermore the planning and design process is manual, with very little optimisation of decisions within the network design software [Dwolatzky and Rajakanthan, 2004]. The selection of line routing, technology, conductor size and transformer size are performed manually.

For the purposes of this research, there are two potential weaknesses in the present design philosophy and tools:

- 1) Lifetime costs are not calculated and are not used to influence decisions in an objective and quantified manner.
- 2) There is very limited optimisation functionality in design tools. The extent to which designs are optimised depends on the experience and skill of the designers and the amount of effort expended in designs.

The extent to which these potential "weaknesses" (including the philosophy to minimise initial capital cost) result in increased lifetime cost is unknown.

### **1.4 RESEARCH HYPOTHESIS**

Based on the analysis thus far, the following conclusions can be drawn:

- Distribution network lifetime costs have many components.
- A rural domestic electrification design method taking lifetime costs into consideration may be desirable for application in South Africa.

- Any method should be applicable to unbalanced, voltage limited feeders supplying small dispersed loads with varying load and settlement characteristics.
- Conductor size appears to have a significant impact on lifetime capital and technical loss cost. The optimisation of conductor size may result in significant savings in lifetime cost. For example, a 1% reduction in lifetime cost in the South African electrification program (with an initial capital cost of at least R10billion [Gaunt, 2003]) will result in a savings of at least R100million.

The scope and boundaries of this research are documented in chapter 3. In order to focus further literature reviews it is necessary that the research hypothesis be introduced as follows:

**It is possible to optimise conductor size for a wide range of electrification network voltage levels and technologies used in South Africa, but with a practical level of detail so that the approach could be used in planning and design functions in the South African utilities and in other countries.**

## 1.5 LOOKING FORWARD

The research will focus on conductor size optimisation in distribution networks supplying predominately domestic consumers.

The following steps are envisaged to test the hypothesis:

- Further literature review will identify the critical components/relationships for conductor size optimisation.
- The scope and boundaries of the research need to be refined.
- A method needs to be developed to meet planning and design needs.
- The accuracy of the method needs to be tested.
- The method needs be applied to practical networks to establish suitability and relevance.
- Conclusions need to be drawn regarding the validity of the hypothesis.

## 1.6 STRUCTURE OF THE THESIS

Chapter 2 summarises the findings of published literature. The scope and boundaries of the research are described in chapter 3. Chapters 4 and 5 review voltage drop and technical loss calculations. Requirements and desirable attributes are identified. Methods combining

technical loss and voltage drop assessment are discussed in chapter 6. Chapter 7 provides an overview of the proposed method for conductor size optimisation and voltage drop calculation. Chapters 8 to 13 document and test the individual components of the method. The method components are combined in software in chapter 14, and in chapter 15 the method is applied to a practical network. Chapter 16 concludes with a summary of the findings and assessment of the research hypothesis.

## 2. CONSIDERATIONS FOR THE OPTIMISATION OF CONDUCTOR SIZE IN SOUTH AFRICAN DOMESTIC ELECTRIFICATION

This chapter introduces factors that should be taken into consideration for the optimisation of conductor size in South African rural domestic electrification networks. It forms a building block for more detailed analysis in subsequent chapters. The distribution technologies and voltage levels commonly used in South Africa are introduced. The evaluation of alternatives based on lifetime cost is discussed. The characteristics of load and network models are highlighted. The chapter concludes with a discussion on South African voltage variation management, including voltage limits.

### 2.1 SOUTH AFRICAN DISTRIBUTION NETWORK VOLTAGE AND TECHNOLOGY

Distribution networks are comprised of two sub-systems; MV distribution and LV distribution. In the United States the MV and LV networks are usually referred to as primary and secondary distribution respectively [Willis, 1997].

MV Technology	Number of conductors	Voltage reference	Standard MV voltages	Comments
Three phase 3 wire (delta)	3	Phase to phase	11kV, 22kV, 33kV	No neutral conductor. The neutral is earthed at the source only. Distribution transformer MV windings insulated for phase to phase voltage.
Single phase (delta) also referred to as Phase-to-phase	2	Phase to phase	11kV, 22kV, 33kV	
Single Wire Earth Return (SWER)	1	Phase to Neutral (Earth)	19kV	Directly connected to 33kV distribution networks with neutral earthed at source. Supplied by SWER MV/19kV isolating transformer when connected to 11kV and 22kV networks.

Table 2.1.1: South African standard MV distribution voltages and technologies

Standard South African MV distribution voltages [SABS 1019, 1985] and technologies are summarised in table 2.1.1. Other distribution voltages (3.3kV, 6.6kV) have been used, but are avoided in network strengthening and expansion in Eskom Distribution. The three phase 4 wire MV distribution technology used in the United States [Willis, 1997] is not utilised much in South Africa (a few municipalities have built systems).

LV Technology	Number of conductors	Voltage reference	Standard LV voltage	Comments
Three phase 4 wire (star)	4	Phase to phase	400V	A neutral conductor is present (combined neutral and earth or separate earth). Single phase 230V loads are connected between phase and neutral. Large loads are supplied with three phase 400V.
Single phase (star)	2	Phase to Neutral	230V	A neutral conductor is present. All loads are supplied with single phase 230V.
Bi-phase (180° phase shift) also referred to as dual phase	3	Phase to Neutral	230V	A neutral conductor is present (centre tap of single phase winding at source transformer). Single phase 230V loads are connected between phase and neutral. Large single phase 480V loads are connected between phase and phase.

Table 2.1.2: South African standard LV distribution voltages and technologies

In alignment with IEC 38 [1994], the standard LV service voltage in South Africa is 400/230V [DME, 1996]. Other LV voltages between 500V and 1kV are provided for by the DME [1996] and are mainly used in mining applications.

The method developed by this research must cater for all of the standard technologies and voltage levels used in South Africa.

## 2.2 LIFETIME EVALUATION OF NETWORK ALTERNATIVES

In the analysis of planning and design implications in electricity distribution, Gaunt [1988] states that for South African network design *"The lifetime cost should be taken into consideration by capitalising the cost of losses. This may lead to a choice of equipment ratings larger than needed to meet the thermal and voltage constraints."*

The IEC 287-3-2 [1995] provides a method for optimal conductor sizing incorporating technical loss costs, and observes that the selection of cable sizes is historically focused on minimising the initial investment cost. It recommends that the cost of losses over the life of the cable should be included in cable sizing analysis such that the total lifetime cost is minimised.

IEC 287-3-2 [1995] focuses on cable sizing, but the principle of lifetime cost minimisation should be applied to all network components and planning decisions (voltage levels, technology, feeder size), and incorporate all anticipated costs that may be sensitive to the network alternatives.

When evaluating alternatives, common costs can be ignored if the alternatives do not have a bearing on these costs [Sellick, 1999]. If alternatives are limited to the selection of equipment, such as cable sizes, common costs can include operating and maintenance costs if these costs are not significantly affected by equipment selection [Sellick, 1999].

Planners and designers are limited to standard equipment specifications including voltage levels and cable/conductor sizes [Willis, 1997]. For a particular application a decision has a range within which it provides the most economic solution. Data accuracy is important, but only to the extent that it influences decisions. The IEC 287-3-2 [1995] concludes that considerable savings can be achieved using data based on reasonable estimates.

According to the NRS 034-1 [1999], the basis of lifetime costing is the conversion or "discounting" of all future income and expenditure to the "present value". Lifetime evaluation requires the analysis of costs over the expected lifetime of the distribution network. Equipment lifetimes used in evaluations vary between countries and equipment types:

- The NRS 034-1 [1999] states that the average economic life of distribution equipment is between 20 and 25 years.
- The equipment lifetime for distribution planning evaluations in Sweden is 30 to 35 years for overhead lines, and 25 years for transformer substations [Lasu, 1970].

The planning and design objective to minimise network lifetime cost (as identified by IEC 287-3-2 [1995] and Willis [1997]) assumes that the optimal network minimises the lifetime cost incurred by the utility. The objective assumes that lifetime utility revenue and non-technical losses are not significantly affected by network planning and design decisions. This assumption may not be valid. The errors may be significant and need to be assessed.

The cost elements (for inclusion/omission) and data requirements for rural domestic electrification conductor size optimisation need to be identified. Discounting methods need investigation. The life of conductors needs to be established for planning and design evaluations.

## 2.3 OPTIMISATION OF NETWORK PLANNING AND DESIGN DECISIONS

Khator and Leung [1997] review published research for the optimisation of distribution planning decisions including the location of substations, location of feeders and design of feeders. Methods vary depending on the optimisation objective and availability of input data, and include heuristic and algorithm approaches and Artificial Intelligence / Expert-Systems.

Dwolatzky [2002] provides an overview of research work performed at the University of the Witwatersrand on the optimisation of LV network design decisions for South African grid electrification projects.

Numerous optimisation objectives and methods have been researched. The optimisation objective for this research needs to be clearly defined. A suitable optimisation method needs to be selected or developed.

## 2.4 ELECTRICAL LOAD MODELS

### 2.4.1 Importance of load modelling

In an analysis of network planning and design decisions in electricity distribution, Gaunt [1988] states "*The loads for which the network is to be designed have a major influence on the cost of the network. Therefore it is important neither to overestimate the loads, resulting in over-capitalisation, nor to underestimate them and incur higher operating and reinforcement costs.*"

Willis [1997] states that a "*model is more important than the solution algorithm when considering distribution planning*".

Brice [1992] analyses the importance of network and load models and notes that the increased complexity required for more advanced load models is only justified if the results are sensitive to the issues described in the enhanced models, and suitable data is available for practical application.

Three principles are critical; a good load model is essential for analysis and decision making, the outputs/accuracy of an algorithm are only as good as the load model, and the suitability of different load models depends on the sensitivity of the results to the load model and the availability of load data.

#### 2.4.2 Load coincidence and diversity

For the purposes of technical loss demand cost evaluation Nickel and Braunstein [1981] conclude that when analysing different utility approaches to demand costs "*There is a major difference of opinion, and a certain amount of confusion, concerning the diversity of load classes.*"

Hamilton [1944] states that "*A number of load curves may be added to determine some characteristics of a composite load from known values of the individual loads which comprise it. The resulting peak load, minimum load, load factor, or time of the peak are characteristics usually sought, but there may be many others.*"

Bary [1945] researches the relationships between the number of consumers, coincidence factors and Load Factors:

- Referring to load coincidence Bary [1945] observes that "*These conditions are not subject to precise mathematical formulations, and their resultant effect will be different for different communities and different climatic, social, and political conditions.*"
- Suitably accurate load models can only be derived from load recordings, and must be checked periodically to detect the effects of changing conditions.
- Statistically stable results for engineering analysis can be obtained from groups of 30 to 50 consumers.

Domestic loads are stochastic [Herman, 1993b]. In LV networks supplying relatively few customers the errors in voltage drop calculations can be large due to inadequate treatment of the stochastic nature of the load [Sellick and Gaunt, 1995].

The following principles are important; a composite load can be derived from models of its individual loads, models of individual loads can be derived from the known values of a group of loads that adequately describe the group and load research is essential for the development of load models. The stochastic nature of domestic loads needs to be adequately described. South African load research needs to be reviewed.

#### 2.4.3 Load classification

The SABS 0150 [1983, subsequently withdrawn] part 3: Guidelines for the design of electricity distribution networks in residential townships states "*Simultaneous maximum*

*demand is dependent upon the class of the residential property, climatic conditions, consumer habits, and the Supply Authority's control measures. The figure must be adjusted to allow for the diversity appropriate to the number of consumers in the group being considered."*

*"Electric energy consumption is influenced by a high number of external variables: the temperature, the type of the day (Sunday, Monday, working day, etc.), the economic activity, etc."* [Bilbao et al, 2001].

There are three key concepts contained in the above statements; the load model will vary for different consumers and environments, load models must be based on local (South African) load research, and load diversity is related to the number of customers.

#### 2.4.4 Load voltage dependency

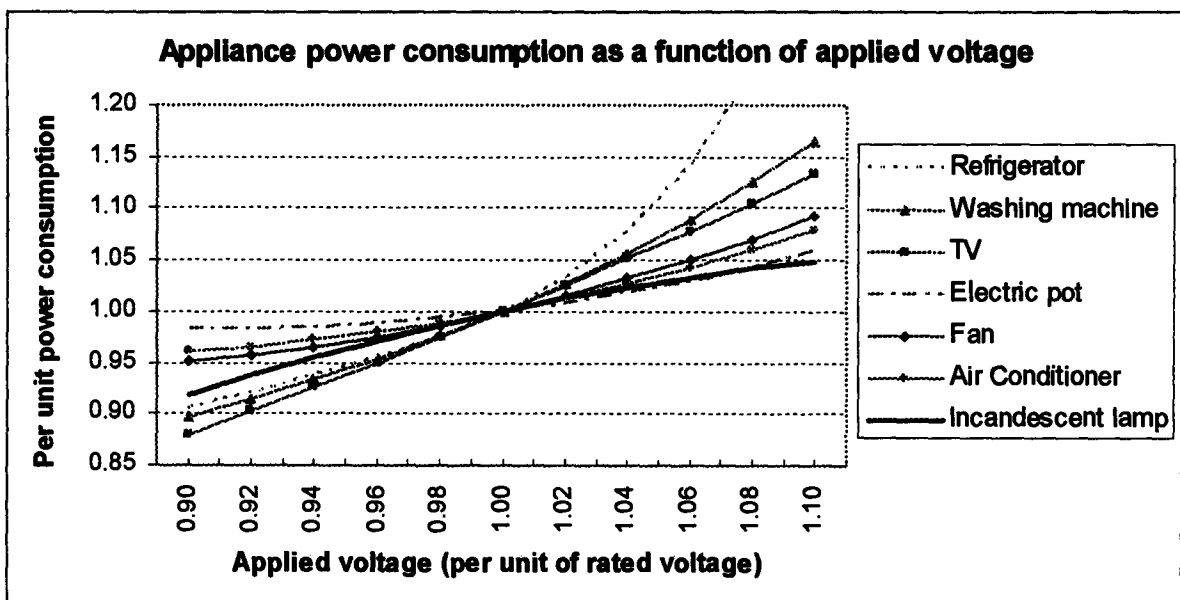
The amount of active and reactive energy consumed by appliances varies with the magnitude of the applied voltage [Mielczarski and Michalik, 1998]. Considerable research into the voltage dependency of loads has been performed for steady state and dynamic system modelling [IEEE, 1994], and the effects on demand and energy consumption due to conservative voltage reduction.

Most loads will draw more active and reactive power if the supply voltage is increased. The possible increased consumption must be considered in light of the types of load being supplied. Thermostatically controlled heating devices (such as stoves and hot water cylinders) consume energy at a faster rate when the voltage is higher. However these devices achieve their function in less time so unless their efficiencies vary significantly with the magnitude of the applied voltage, they consume the same amount of energy in order to fulfil a given function. The voltage magnitude effects the time for which thermostatically controlled heating devices draw load, and thereby affects the load co-occurrence [IEEE, 1994]. The applicability of load recordings to other networks needs to be considered if the voltage variations in these "other" networks are significantly different to those of the network/customers upon which the load data is based.

The results of research by Mielczarski and Michalik [1998] concluded that for every 1% reduction in the average voltage supplied to the consumer the energy consumption reduces by between 0.9% and 1.6% for residential, 0.5% to 1.2% for commercial, and 0.6% and 1.2% for industrial loads. Other recommended values by Kirshner and Giorsetto [1984] for different

load types as a function of a 1% reduction in average voltage are a energy consumption reduction of 0.76% for residential, 0.99% for commercial, and 0.41% for industrial loads. Measurement of 15 distribution circuits supplying a non-coincident peak demand of 80.2MVA of mixed load in the United States (which included rural areas), resulted in an average 0.71% reduction in energy consumption per 1% reduction in the source voltage [Warnock and Kirkpatrick, 1986]. Selected results of an EPRI laboratory analysis of common North American household appliances are plotted in figure 2.4.4.1 below.

Figure 2.4.4.1: Typical appliance power consumption as a function of applied voltage as derived by EPRI from a statistical analysis of laboratory measurement [Chen et al, 1995]



While the power drawn by an appliance may vary with the magnitude of the applied voltage at a particular instant in time, the total energy consumed by the appliance may not vary significantly over an extended period of time. Energy consumption will only increase for constant impedance or current type loads that are not self regulating (i.e. they do not control their operation), and energy consumption is affected by the magnitude of the applied voltage.

“Power consumption” can be a misleading term. The results of the EPRI models can be used when evaluating short-term (measured in minutes) demand reduction due to voltage variations, but should not be directly applied to assess the longer-term (measured in hours, days, months or years) impact of voltage variations on energy consumption.

In evaluating the costs associated with voltage drop across distribution transformers Nickel and Braunstein [1981] observe that a reduction in voltage can result in lost revenue due to reduced consumer energy consumption, and result in reduced utility demand costs due to a reduction in maximum demand. The cost of the lost revenue is the lost revenue minus the utility's cost of this energy. The cost due to reduced demand is a cost saving (reduction in cost), and is dependent on the demand charge paid by the utility. The net cost due to voltage drop is the cost of lost revenue minus the cost saving due to reduced demand. In certain applications increased voltage drop could lead to a net cost savings (cost of lost revenue is negative). This created scepticism among utilities, and Nickel and Braunstein [1981] adopt the practice that the cost of voltage drop (for the purposes of distribution transformer assessment) is the cost of voltage regulating equipment (to compensate for the voltage drop) including voltage regulators, capacitor banks and OLTC transformers. Nickel and Braunstein [1981] concluded that "*the energy cost of regulation, or lost revenue due to reduction in energy minus the utility's cost of this energy, is still under study.*"

The impact of conductor voltage drop on utility lost revenue and maximum demand needs to be assessed.

#### 2.4.5 Impact of load voltage dependency on network analysis results

Stojanovic et al [1999] investigate the effect of load voltage dependency on an IEEE 12.66kV 32 branch test network. The MV voltage drop is dependent on the load model and MV source voltage, and is approximately 10% of the MV source voltage. The MV source voltage was varied and the line currents, losses and node voltages were compared for constant power, current and impedance load types. The results indicate that in distribution networks, the currents, voltages and losses are sensitive to the load type (voltage dependency) when the MV source voltage is at extremes (0.9 and 1.1 of nominal voltage). However for typical MV source voltages (1.05 of nominal) changing the load voltage dependency had little impact on the load-flow. This implies that for planning and design, assuming that the MV source voltages are within normal limits (typically between 1.0 and 1.05 per-unit) the load voltage dependency is not critical. Constant current models appear to be sufficiently accurate and the most suitable model for distribution network planning and design studies. This is supported by Brice [1992].

In South Africa "*Residential loads can be approximately modelled as constant current in static load flow studies*" [Herman and Heunis, 2002]. Gaunt [1994] notes that South African residential load research data is captured in amps, and that conversion to impedance or

power models will introduce additional errors. Presently South African domestic load research data (see section 2.4.9) does not provide information on load voltage dependency. Possible additional accuracy via the modelling of constant power or impedance loads is offset by the uncertainty in the appropriate load model to be used in a particular application.

The optimisation of conductor size is expected to affect conductor voltage drop and consumer voltage variations. There are two implications for this research:

- 1) Technical load loss varies with conductor size. Lifetime technical load loss cost hence varies with conductor size.
- 2) Customer energy consumption and demand vary with conductor size (for loads that are not constant power) due to voltage drop over the conductor. Utility bulk energy purchase costs and revenue hence vary with conductor size.

The sensitivity of South African rural domestic electrification network voltage drop and technical load loss calculations to load voltage dependency needs to be assessed (see chapter 9).

The sensitivity of conductor lifetime costs to changes in utility bulk energy purchase costs and revenue (as a result of conductor voltage drop and load voltage dependency) needs to be assessed (see chapter 10).

#### 2.4.6 Domestic load modelling assumptions

In order to simplify the calculation process, the following assumptions have been widely accepted with respect to South African domestic electrical load [Herman, 1993b; Herman, 1993a; Herman and Gaunt, 1997]:

- There are no generators within the residential network (no negative load current). The impact of distributed generation is discussed in section 2.5 and is not expected to significantly impact South African rural domestic grid electrification network design.
- No consumer will draw an average current for the duration of a single sampling interval of more than the installed circuit breaker size. This assumption is justified for sample intervals greater than the protection delayed tripping characteristics. For the sample size of  $\geq 5$  minutes (the time interval used in the South African domestic load research) this assumption holds.

- The power factor for each consumer is unity. In upper income areas, where motors are common (typically in tumble-dryers, washing machines, swimming pool pumps, and air-conditioners), this assumption needs to be analysed. This research is aimed at lower income consumers where the balance of the load is formed by resistive elements that have unity power factor, such as kettles, stoves, space and water heaters, and incandescent lighting, but it is still useful to identify any limits on its wider validity.

The following need to be assessed for South African rural domestic electrification networks; the typical power factor of low-income domestic loads, and the likely errors due to the assumption of unity power factor in load-flow calculations.

#### 2.4.7 Demand Side Management

Demand side management (DSM) devices are often installed by the supply authority to control the load on certain appliances, such as hot water cylinders. DSM devices will impact the load. For the purposes of domestic voltage drop and loss calculation, Sellick [1999] states *"it is assumed that DSM devices if present, are "typical" for the community under consideration, that the percentage penetration is representative for that community."*

The implication for this research is that the domestic load research data described in section 2.4.9 will not be adjusted to account for possible DSM initiatives, and it is sufficient to analyse the load data from the house level, and not appliance level.

#### 2.4.8 Load forecasting

The criticality of adequate load estimation is highlighted by Brown [1996] where it is established that the voltage performance of a newly electrified township (Tambo, South Africa) was below standards shortly (within a year) after its completion. The poor voltage performance is attributed to an underestimation of the load requirement. Strengthening was required shortly after project completion, resulting in increased cost. Over estimation of the load is also undesirable as this may lead to the provision of underutilised capacity, and increased cost.

The load forecast of a comparatively large area can be achieved with greater accuracy than the load forecast of the individual networks that comprise the "large area" [Fisher and Gales, 1971]. When predicting load over comparatively large areas, the forecast errors due to

customer movement and new customers are reduced. Larger load step changes are expected in individual networks as compared to the total load for a larger section of network.

For the purposes of this research, load forecasting techniques should be based on the characteristics of the particular loads supplied by the feeder analysed.

#### 2.4.9 South African domestic load research

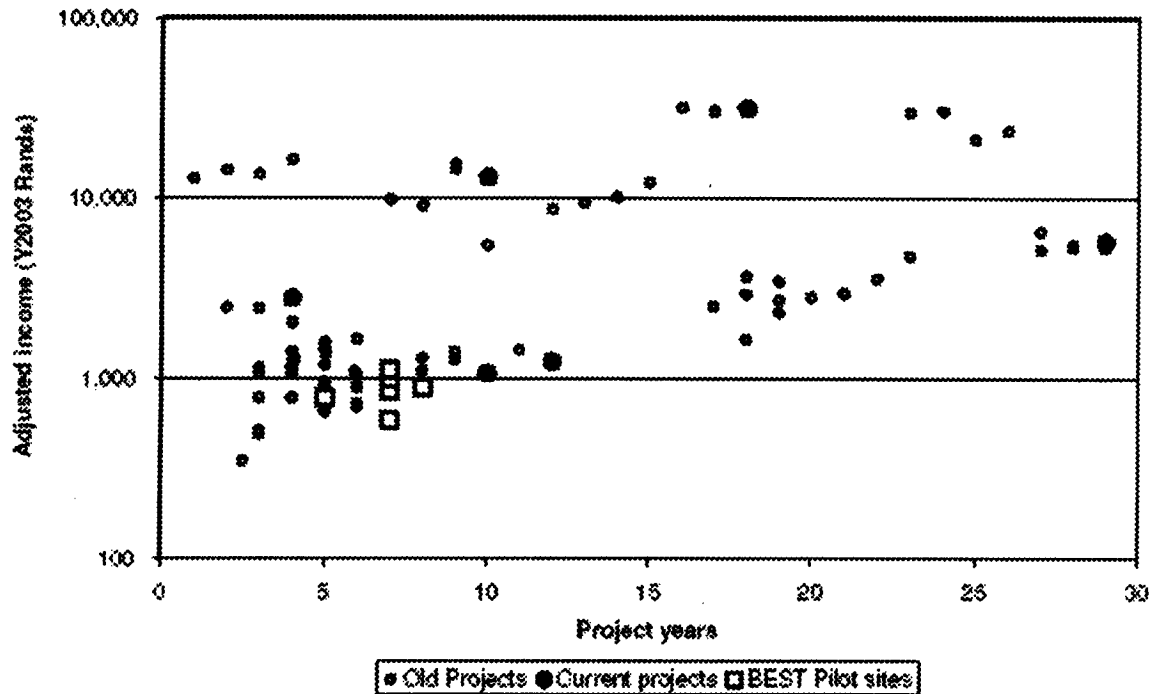
South African domestic load research warrants specific discussion as the nature and availability of load data will influence network load models, and thereby the method proposed by this research.

Pioneering load research investigations by Herman and Gaunt [1991] resulted in the development of synchronised load recorders to measure individual domestic consumer currents within a community. The analysis of initial recordings challenged the assumption that domestic consumer load currents at peak are normally distributed, and led to the hypothesis that domestic loads are best described by a beta distribution [Herman, 1993a; Herman and Kritzing, 1993]. The Herman Beta voltage drop calculation method [Herman, 1993b] was subsequently developed, and is described in section 4.2.1. The South African NRS Load Research project was started in 1994 to collect data characteristics of domestic/residential customers and identify the relationships between household parameters and electricity demand and consumption [Dekenah and Heunis, 1999; Gaunt, 1999].

5 minute average current samples (date and time stamped) are recorded for selected customers in projects representing (as far as possible) the range of domestic customers in South Africa. Load recordings are accompanied by socio-demographic surveys. By the end of 2003 a total of 5681 socio-demographic surveys and 593 million load readings had been collected [Dekenah, 2003]. Wealth and time-electrified are strong determinants of community demand and consumption [Heunis and Dekenah, 2001], and are therefore a good basis upon which to classify loads.

Figure 2.4.9.1 shows the year 2003 status of all domestic load research projects since 1994, mapped upon the axes of greatest sensitivity; Income and time-electrified.

Figure 2.4.9.1: Map of domestic load research projects at end 2003 [Dekenah, 2003]



The “BEST” projects identified in figure 2.4.9.1 are pilot sites assessing the impact of a Basic Electricity Support Tariff, whereby a certain amount of units are provided free each month.

Relatively few projects are poor and old. Load research site selection is targeted at addressing this gap.

The load research is being extended to non-domestic loads typically found in the vicinity of domestic consumers, including schools, clinics and shops [Herman, 2003].

The NRS LR data is, amongst other uses, used to characterise domestic consumer loads [NRS 034-1, 1999], and test the accuracy of voltage drop [Heunis, 2000] and loss estimation techniques [Herman and Heunis, 2002]. Domestic consumer load models, and their application in voltage drop assessment, are discussed in more detail in chapter 4.

For the purposes of this research, methods should consider the South African domestic load research data available, and thereby facilitate the assessment of new techniques that may not have been practically feasible a few years ago.

## 2.5 ELECTRICAL NETWORK MODELS

Sellick and Gaunt [1995] stress that network performance evaluation accuracy is sensitive to the network parameters, including network topology, phasing and line impedance. Referring to LV voltage drop assessment, Sellick and Gaunt [1995] state "*There is a balance between calculation effort, and the risks taken by designing to a less accurate output index.*" This observation also applies to the evaluation of other performance aspects, such as technical losses.

Three principles are important; the network model must be suitably accurate for the intended purpose, errors and simplifications in the network model introduce errors that must be reflected in the confidence associated with results, and the results are only as good as the accuracy of all of the inputs, including both network and load models i.e. very accurate network models may have limited value if the load modelling is poor.

In South Africa LV networks (urban and rural) are operated in a radial configuration.

In rural networks economic distribution is achieved via radial MV feeders running from the supply centre to the various load points [Sen Gupta et al, 1984]. South African MV networks are operated in a radial configuration. Normally open tie points are used for network reconfiguration in the event of faults and planned outages. Many South African rural MV networks are radial with very limited or no interconnectivity.

In urban areas with suitable load densities it is common practice to operate MV networks in looped and/or meshed configurations. In looped and/or meshed networks Fisher and Gales [1971] recommend that cables of uniform current carrying capacity should be used for a particular voltage level. This simplifies operations and enables the establishment of additional in-feed points with a minimum rearrangement of existing feeders. Fault level considerations in meshed networks may also dictate a minimum cable size, and thereby reduce the number of cable sizes considered.

In radial MV and LV networks, such as those used in South African rural electrification, it is common practice to use tapered conductor sizes. The resultant cost savings are expected to offset possible costs associated with future network upgrading and reconfiguration. Willis [1997] observes that due to mechanical and logistic considerations, utilities standardise on a minimum conductor size. Even if a conductor tapering philosophy is applied, the most

common conductor size used is the smallest conductor allowed for the network voltage level [Willis, 1997].

Gaunt [2003] discusses the suitability of distributed generation as a cost effective option for South African electrification, and concludes that *"DG does not represent a lowest cost solution to the energy needs of most customers and, for the purposes of this research [electrification technology and processes], the effect of DG on electrification can be disregarded."*

For the purposes of this research, there is no requirement to include DG in network and load models. However it would be beneficial if the method developed by this research could consider DG (or be enhanced to consider DG) thereby also being applicable in applications where significant DG penetration levels are expected.

For the purposes of this research, distribution network models and analysis:

- can be confined to radial distribution network analysis with no distributed generation,
- should be applicable to both MV and LV networks (however different techniques may be used at MV and LV),
- must consider the characteristics of each network branch (for the analysis of tapered conductor sizing and different line technologies), and
- should accurately model branch impedances.

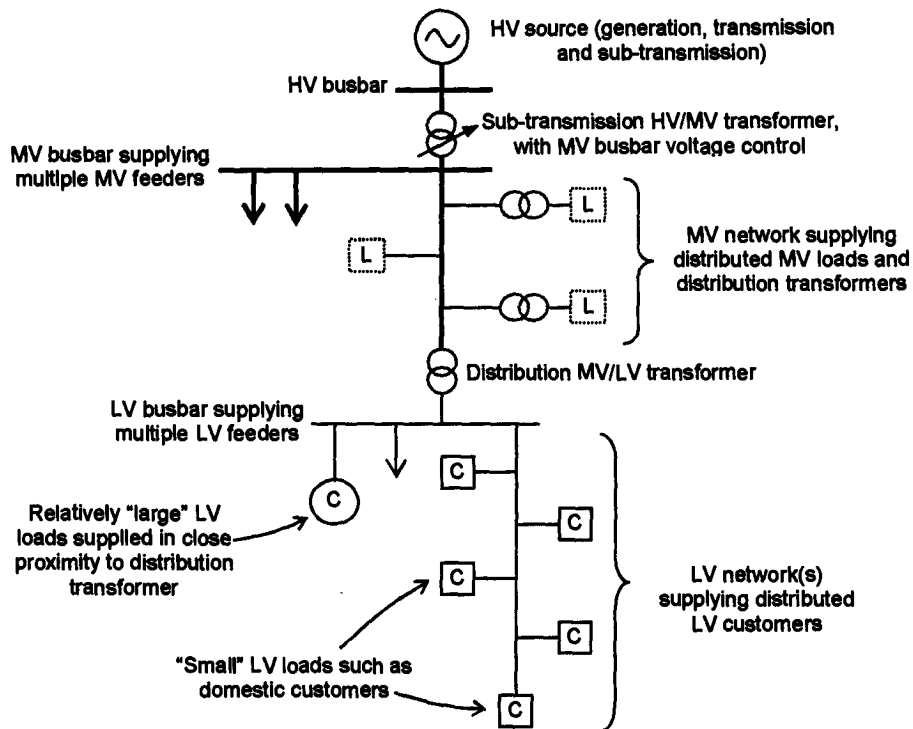
The assessment of DG is not an important requirement for South African rural electrification, but it would be beneficial if the method developed by this research could support DG modelling such that it could be applied in countries/networks where DG assessment is a requirement.

## 2.6 VOLTAGE VARIATION MANAGEMENT

Voltage variation constrains the capacity of rural electrification networks [Agoris and Argiropoulos, 1994]. South African voltage variation management warrants specific discussion.

## 2.6.1 Distribution voltage variation management philosophies in South Africa

Figure 2.6.1.1: Major components of a typical South African distribution network. Line voltage regulators and shunt capacitor banks are not illustrated, but are commonly used



The system depicted in figure 2.6.1.1 is typical of distribution systems in South Africa and many other developing countries, having extensive LV feeders. However, it is less typical of North American systems in which most of the distribution is at MV with very short LV feeders.

The main components of South African distribution network voltage management that need to be taken into consideration for this research are as follows [Carter-Brown and Gaunt, 2006a; Carter-Brown and Gaunt, 2006b]:

- MV busbar voltages at HV/MV substations are kept relatively constant despite variations in the HV and MV networks by automatic control of HV/MV on-load tap change (OLTC) transformers. Small busbar voltage variations occur due to the tap step size and voltage controller bandwidth.
- MV/LV transformers are fitted with de-energised tap switches (DETS) to compensate for voltage drop in the MV and/or LV networks. The DETS is not automated.
- Fixed and switched shunt capacitor banks are used to improve the load power factor, reduce voltage drop and reduce energy losses.

Carter-Brown and Gaunt [2003] research voltage and voltage drop limits in distribution feeders for network planning, design and operations in South Africa. The relevant findings are as follows:

- Fixed tap MV/LV transformers are used in distribution networks. Customers supplied at the LV service level experience the combined effects of the voltage drops and voltage regulation management in both the MV and LV networks. The MV and LV networks must be planned, designed and operated with due consideration for one another.
- Voltage drop limits should consider equipment specifications, operating practices, network status (normal versus abnormal configuration due to contingencies) and contractual/regulatory obligations at the customer service points.
- The primary constraints dictating voltage drop limits are the voltage limit obligations at the customer service point, and the compatibility (voltage requirements) of customer loads and appliances.
- The maximum voltage drop limits are requirements within which the network should be planned, designed and operated. More restrictive limits may be adopted if economically justified by the consideration of technical losses and other lifetime costs.
- The majority of Eskom Distribution's MV and LV networks are limited by voltage drop requirements. This is significant for this research, as voltage drop considerations can be considered a major factor in South African rural domestic electrification network planning and design.

The voltage and voltage drop limits recommended by Carter-Brown and Gaunt [2003] for use in South Africa are not based on a lifetime analysis of the costs associated with voltage drop. In specific applications the optimal economic voltage drop limits (minimising lifetime cost) may be significantly different (larger or smaller) to those recommended. A lifetime analysis (incorporating, for example, technical loss costs) may show that the economic voltage drop limits are less than, equal to, or greater than the maximum limits presently allowed. The economic voltage drop limits are expected to be sensitive to the type of network (urban, rural, buried cable or overhead) and customer (size, load characteristic and spatial location).

With regards to voltage drop limits, there are two potential outcomes for South African rural domestic electrification networks:

- 1) Lifetime costs (not present voltage drop limits) dictate the scope of plans/designs: If appropriate the voltage drop limits could be reduced or increased to coincide with the economic voltage drop limits. Alternatively network planning and design could

- Line voltage regulators are used to compensate for unacceptably high levels of voltage variation, and are usually used in rural networks.
- The planner/designer of a future network assumes the network will be operated in a reasonable manner (voltage control and tap settings, balanced loads and appropriate configuration of normally open points).

The method developed by this research must be appropriate for the assessment of voltage limited networks containing OLTC and DETS transformers, shunt capacitor banks and voltage regulators. The impacts of voltage control settings, tap settings, load balancing and normally open point configuration need to be included.

### 2.6.2 Voltage limits, voltage drop, voltage variation and voltage regulation

The terms voltage limits, voltage drop limits, voltage variation and voltage regulation should not be confused:

- Voltage limits are the maximum and minimum voltages that should not be exceeded at a particular point in the network (usually a customer point of supply).
- Voltage drop limits are the maximum permissible voltage drops for particular networks. Voltage drop limits are directly related to voltage limits. Voltage drop limits are selected so that when combined with the distribution voltage regulation philosophy (transformer tap settings and shunt compensation), the voltage limits will be met.
- Voltage variation is the difference between the maximum and minimum voltage at a point in the network (as a result of stochastic load behaviour and network parameters). The maximum voltage variation limit is the difference between the voltage limits.
- Voltage regulation is the action(s) taken to restrict the extent of the voltage variation.

### 2.6.3 Voltage drop limits in MV and LV distribution networks

Reliability requirements and economic objectives aside, the purpose of the distribution network is to provide customers with power at voltage levels for which appliances and equipment will operate with acceptable levels of performance and efficiency [Willis, 1997].

Lakervi [1984b] states that "*Voltage drop is the most popular dimensioning criterion in electricity distribution network design.*"

incorporate lifetime cost evaluation, within the requirements of the present voltage drop limits.

- 2) Present voltage drop limits (not lifetime costs) dictate the scope of plans/designs: For certain network/customer types, it would not be necessary to include lifetime cost evaluation as the plan/design is dictated by the voltage drop requirement. The possibility of increasing voltage drop limits would need to be assessed. This may require revisions to standards for voltage limits. The impact of increased voltage variation on customer appliances would need careful consideration.

The suitability of present South African voltage drop limits is of particular interest in rural domestic electrification networks as:

- The capacities of these networks are primarily constrained by present voltage drop limits.
- The Load Factor is relatively low (typically less than 15% [Sellick, 1999]). The cost of load losses may not be very significant. The time duration of "low" voltage conditions may be short.
- The customer appliances are relatively basic (typically only hotplates, kettles and lighting) [Gaunt, 2003]. The operation, efficiency and lifespan of these "basic" appliances may not be significantly affected by increased voltage drop limits.
- Lower voltages reduce the performance of appliances such as cooking and heating (they take longer to perform the same function). Lower voltages at peak loading may influence consumer behaviour and shift load to periods of reduced loading (and improved voltages). Increased voltage drop limits may act as a Demand Side Management signal, with benefits for the upstream network and generation.
- Reduced voltages during peak loading result in decreased energy consumption (see section 2.4.4). The South African generation peak coincides with the domestic load peak. Reduced domestic peak consumption benefits generation.
- Gaunt [2003] identifies that in the context of the relatively high costs and low returns, South African electrification is understood as being performed for social reasons, and *"if the electrification is to alleviate poverty, a lower quality of supply (wider voltage regulation, more interruptions) will be acceptable if it does not diminish the efficiency of delivering the benefit"*. In the context of this research, increased voltage variation/drop limits should be considered if these increased limits result in reduced lifetime cost, and do not significantly reduce the benefits of electricity to poor (the vast majority of electrification) customers.

Looking ahead, the method developed by this research needs to consider both the MV and LV network. The network voltage drops and consumer voltages associated with different conductor sizes need to be assessed.

## 2.7 LOOKING FORWARD

The scope and boundaries for the optimisation of conductor size in South African rural domestic electrification need to be refined. The following requirements have been identified for further consideration:

- The method must cater for all of the standard distribution technologies and voltage levels used in South Africa.
- MV and LV networks should be analysed in the same study so that interdependencies between these network levels can be assessed.
- The conductor size must be optimised. The optimisation objective still needs to be defined.
- The cost components significantly affected by conductor size need to be identified and included. Common costs can be ignored.
- Changes in utility revenue due to conductor voltage drop may need to be taken into consideration.
- Suitably accurate load models are critical, and must adequately describe the stochastic nature of domestic consumers. It is expected that South African load research will directly affect the load models used in the research.
- The network can be confined to radial configurations. Each branch must be modelled.
- The network model must support OLTC and DETS transformers, shunt capacitor banks and voltage regulators. The impacts of voltage control settings, tap settings, load balancing and normally open point configuration need to be included.
- The MV and LV voltage drops and consumer voltages need to be calculated.

The possible errors due to assumptions regarding domestic consumer voltage dependency and power factor need to be assessed for typical South African rural domestic electrification networks.

The optimal voltage drops (based on the optimum conductor sizes) for South African rural domestic electrification networks need to be compared with South African voltage drop limits.

### **3. RESEARCH SCOPE AND BOUNDARIES**

An initial set of requirements has been identified for the optimisation of South African rural domestic electrification conductor sizes. In this chapter the scope and boundaries of the research are refined further.

#### **3.1 NETWORK TOPOLOGY FOR CONDUCTOR SIZE OPTIMISATION**

Given the location and load requirements of a group of customers, the planner/designer has control over the following major components that affect the network lifetime cost and voltage drop:

- MV voltage level (usually dictated by existing distribution voltage for extensions off existing networks). Note that in South Africa the LV voltage level is fixed at 400/230V.
- MV and LV line technologies. The technologies may be restricted based on the availability of a three phase supply.
- MV and LV conductor types (overhead line, overhead cable, buried cable) and sizes.
- MV/LV distribution transformer sizes and locations, which dictate the LV feeder zone sizes (the lengths of LV networks and numbers of customers supplied by distribution transformers).

The designer has little or no control over the "village" layout (the location of customers, roads etc) [SABS 0150, 1983]. Network planning and design line routing is typically based on the minimum total feeder length required to connect the network source and loads within the constraints imposed by environmental restrictions [Cartina et al, 1998]. According to the SABS 0150 [1983, subsequently withdrawn] "*The layout of the LV network is normally radial and is decided on an arbitrary basis and several alternatives may have to be considered to obtain an optimum layout*". Herman [1992] states "*For deciding on the route [of LV feeders], the most common method relies on experience.*"

The SABS 0150 [1983, subsequently withdrawn] recommends that alternative LV supplies are only provided to critical loads such as shopping centres and hospitals. For the purposes of this research, all networks are radial and cables sizes are selected for normal network operation with no alternate supplies. This is valid for South African rural domestic electrification.

This research is confined to the selection of the optimal conductor size in each network branch given the following user defined parameters:

- Network routing, connectivity and line lengths. Line routing algorithms have been developed for network design [Dwolatzky, 2002]. Line routing is considered an input to this research.
- Branch voltage level (e.g. 11kV, 400V).
- Branch technology (e.g. three phase, single phase, bi-phase).
- Customer load characteristics, customer locations and phasing (connection of single phase loads to three phase and bi-phase networks).

In addition to the conductor size, the extent to which the network is optimised will be influenced by the feeder routing, voltage levels and technologies. Manual manipulation of the network model is required to assess the impact of these factors. This method should be sufficient to:

- Enhance present conductor size optimisation.
- Provide an objective assessment of present conductor size optimisation methods and their impact on network lifetime cost.

Further research on optimisation techniques could develop the method further such that other variables (feeder routing, voltage levels, technologies) are included in the optimisation. As this research is focused on conductor size optimisation, other variables have not been considered further.

Due to the considerable uncertainty in future loads, South African domestic electrification networks may be planned/designed with an upgrade path such that initial capital expenditure is reduced [Gaunt, 2003]. Network reinforcement in future years needs to be catered for.

LV customers experience the combined effects of the MV and LV networks. It is common that MV and LV networks are planned and designed in relative isolation from one another

Component	Description	Constraint/ Requirement	Include/ Omit	Justification for Include/Omit
Conductor fault level ratings	Fault currents in excess of conductor fault level rating may result in costs due to conductor damage, penalties and customer claims as a result of outages, and may have safety implications. Conductor fault level ratings are a constraint as violation of the fault level rating may result in conductor damage [Sellick, 1999].	Constraint	Omit	Conductor fault level ratings vary with conductor size. In a South African urban township application, Jones and Gaunt [1987] obtained a 4% to 5% reduction in network capital cost by reducing fault levels. In rural domestic electrification the cost savings associated with reduced fault level are insignificant as these networks are voltage limited and MV/LV distribution transformers are generally $\leq 100\text{kVA}$ . Conductor size selection in South African rural domestic electrification networks is not constrained by fault level rating. Conductor fault level ratings do not need to be included.
Conductor thermal overloading due to load current	Conductor thermal overloading due to excessive load current may result in increased cost due to conductor damage, penalties and customer claims as a result of outages, and may have safety implications. Conductor thermal ratings are a constraint as violation of the thermal rating may result in conductor damage.	Constraint	Include	Conductor thermal ratings vary with conductor size. Individual branches in voltage limited rural electrification feeders may be thermally constrained where these branches supply relatively large loads in relative close proximity to the feeder source. Conductor thermal limits must be included as a constraint. Conductor thermal limit assessment will be confined to constraining the selection of conductor sizes such that thermal constraints are met. The costs associated with thermal overloading (should a conductor be used that has a rating less than the constraint) are not included in lifetime costing. This is valid as conductor thermal limits are a constraint and must be met for the purposes of conductor size optimisation in network planning and design.
Consumer voltage limits	Consumer voltages need to be kept within the limits set by utility and government regulations. Violation of consumer voltage limits may result in penalties, fines and customer claims. Voltage limits are considered a requirement [Sellick, 1999].	Requirement	Include	Conductor voltage drops vary with conductor size, thereby impacting consumer voltages. As per section 2.6 the assessment of voltage limits must be included such that the voltage drops and voltage limits associated with optimal conductor sizes can be assessed. South African low-income domestic consumers are relatively financially insensitive to voltage variation [Gaunt, 2003] and seldom claim damages as a result of voltages outside of regulatory limits. The impact of claims, fines and penalties on lifetime cost is not required. If the results of this research show that the optimal voltage drops (based on the optimised conductor sizes) are outside of the limits associated with regulatory standards (specifically the NRS 048-2 [2004]), further research should incorporate these aspects. In summary, the calculation of consumer voltages must be included, but the costs associated with consumer voltage limit violation are omitted.

Table 3.2.1a: Constraints and requirements for consideration in South African rural domestic electrification conductor size optimisation

(usually different resources are used), and this can lead to sub-optimisation [Carter-Brown and Gaunt, 2003]. Optimal approaches consider both MV and LV networks. For the purposes of the research, both the MV and LV networks should be considered such that sub-optimisation is avoided.

## **3.2 CONDUCTOR SIZE OPTIMISATION CONSIDERATIONS**

The components identified for consideration in the conductor size optimisation are listed in table 3.2.1a, 3.2.1b and 3.2.1c. As per Sellick [1999] each component has been categorised as being a constraint or requirement (see section 1.2). A justification is provided for the decision to either include or omit each component.

Component	Description	Constraint/Requirement	Include/Omit	Justification for Include/Omit
Consumer voltage unbalance limits	The voltage unbalance at the consumer point of supply needs to be kept within the limits set by utility and government regulations. Violation of consumer voltage unbalance limits may result in penalties, fines and customer claims. Voltage unbalance limits are considered a requirement (in keeping with consumer voltage limits).	Requirement	Omit	<p>Conductor voltage drops vary with conductor size, thereby impacting consumer voltage unbalance.</p> <p>Load unbalance and unbalanced network technologies need to be considered for network modelling as unbalanced loads and network technologies affect voltage drop and technical losses [Herman et al, 1998; Chen, 1995].</p> <p>South African rural domestic electrification consumers seldom require three phase supplies [Gaunt, 2003]. The impact of voltage unbalance on consumers is not required for the assessment of lifetime costs. If the results of this research show that the optimal voltage unbalance (based on the optimised conductor sizes) are outside of the limits associated with regulatory standards (specifically the NRS 048-2 [2004]), further research should incorporate these aspects.</p> <p>In summary, the calculation of voltages and technical losses needs to consider load and network unbalance. Consumer voltage unbalance limits and the costs associated with consumer voltage unbalance limit violation are omitted.</p>
Consumer voltage flicker, dip and harmonic limits	Voltage flicker, dips and harmonics at the consumer point of supply needs to be kept within the limits set by utility and government regulations. Violation of voltage flicker, dip and harmonic limits may result in penalties, fines and customer claims. Consumer voltage flicker, dip and harmonic limits are considered a requirement (in keeping with consumer voltage and unbalance limits).	Requirement	Omit	<p>Conductor voltage drops and downstream fault level vary with conductor size, thereby impacting voltage flicker, dips and harmonics.</p> <p>South African rural domestic consumer appliances are relatively basic (typically only hotplates, kettles and lighting) [Gaunt, 2003]. Voltage flicker, dips and harmonics are omitted as the customer loads are unlikely to either cause or be affected by voltage flicker, dips and harmonics.</p>
Network reliability (sustained customer interruptions)	The number and duration of sustained customer interruptions needs to be kept within the limits set by utility and government regulations. An increase in interruptions may result in reduced revenue, penalties, fines, customer claims and economic cost to customers.	Requirement	Omit	<p>In interconnected networks conductor size affects the amount of load that can be supplied via network reconfiguration following an unplanned outage, thereby impacting network reliability.</p> <p>The economic cost of interruptions for South African rural low-income domestic customers is low [Gaunt, 2003]. South African rural domestic electrification networks are radial with little or no interconnectivity. According to Willis [1997] the conductors in a set (for use in conductor size optimisation) should be selected taking into consideration reliability requirements. For this research, different conductor sizes in a set are assumed to have similar reliability. The impact of sustained customer interruptions is omitted as conductor size selection is not expected to significantly affect South African rural domestic electrification network reliability. The implications for reliability should be researched if results show that optimum networks have characteristics that could degrade performance.</p>
Conductor capital cost	Conductor capital costs include material, labour and transport costs in year 1 and in future years for reinforcement.	Requirement	Include	<p>Conductor capital costs vary with conductor size.</p> <p>Conductor capital costs are a significant lifetime cost in the conductor size optimisation performed by IEC 287-3-2 [1995], Willis [1997], Sellick [1999], Curcic et al [2001], Mandal and Pahwa [2002] and Falaghi et al [2005], and need to be included.</p>

Table 3.2.1b: Constraints and requirements for consideration in South African rural domestic electrification conductor size optimisation

Component	Description	Constraint/ Requirement	Include/ Omit	Justification for Include/Omit
Kiosk, pole top box, circuit breaker and metering capital costs	This equipment is typically installed with conductors as part of the distribution network. Capital costs include material, labour and transport costs.	Requirement	Omit	The cost of this equipment does not vary significantly with conductor size, is considered to be a common cost and can be omitted for conductor size optimisation lifetime costing [Sellick, 1999]. The effect of consumer circuit breaker limiting may need to be considered in load models (see section 4.2).
Operating and maintenance cost	Conductor operating and maintenance costs arise due to routine network operations and maintenance over the conductor lifetime.	Requirement	Omit	According to Sellick [1999] conductor operating and maintenance costs do not vary significantly with conductor size, and can be ignored for conductor size optimisation lifetime costing.
Utility bulk energy purchase costs	Cost incurred by the utility for the purchase of bulk power from generation/transmission and utility owned generators. Utility bulk purchases include all energy dissipated in and supplied by the distribution network, including consumer loads, technical losses and non-technical losses (see section 5.1.1).	Requirement	Include	As per section 2.4.4, consumer energy consumption and demand vary with voltage for loads that are not constant power. Conductor voltage drop and technical load losses vary with conductor size [Sellick, 1999]. Conductor size optimisation may affect consumer voltages, and hence impact consumer energy consumption and demand. Utility bulk purchase costs need to be included in conductor size optimisation due to the impact of conductor size on both technical losses and consumer energy consumption and demand. The significance of changes in consumer energy consumption and demand (due to conductor voltage drop) for conductor size optimisation needs to be assessed.
Utility revenue from energy sales	Revenue received by the utility due to the sale of energy to consumers.	Requirement	Include	Consumer energy consumption and demand vary with voltage for loads that are not constant power (see section 2.4.4). Conductor voltage drop varies with conductor size. Conductor size optimisation may affect consumer voltages, and hence impact consumer energy consumption and demand. Utility revenue may need to be included in conductor size optimisation due to the impact of conductor size on consumer energy consumption and demand.
Technical losses	From the perspective of transmission and generation, distribution technical losses are indistinguishable from load [Tobin and Glynn, 1991]. Technical losses may increase utility bulk energy/demand and result in increased utility bulk energy/demand purchase costs.	Requirement	Include	Technical load losses vary with conductor size [IEC 287-3-2, 1995; Willis, 1997; Sellick, 1999; Curcic et al, 2001; Mandal and Pahwa, 2002; Falaghi et al, 2005], may affect bulk energy purchase costs and need to be include in conductor size optimisation.
Non technical losses	Non-technical losses are predominately due to de-calibration of meters, bypassing of meters, damaged meters, errors and estimations in the billing system, and energy theft due to customers not registered in the billing system [Cespedes et al, 1983; Davidson et al, 2002].	Requirement	Include	Non-technical losses are significant in developing countries, with a value approximately 20% reported for the Zambian distribution networks [Mupwaya, 2003]. Non-technical losses reduce utility revenue (not all potential sales revenue is collected) and thereby reduce the effective price paid by consumers for energy. Consumer energy consumption and demand may vary as a result of conductor voltage drop. The change in utility revenue (due to changes in consumer energy consumption and demand as a result of conductor voltage drop) may be affected by the level of non-technical losses. Non-technical losses need to be included in conductor size optimisation. The significance of non-technical losses for conductor size optimisation needs to be assessed.

Table 3.2.1c: Constraints and requirements for consideration in South African rural domestic electrification conductor size optimisation

Referring to tables 3.2.1a, 3.2.1b and 3.2.1c, the only constraint to be included is conductor thermal rating. The rest of the components to be included are requirements.

Table 3.2.2 summarises the components included by previous conductor size optimisation methods (which are reviewed in more detail in subsequent chapters).

Method	Conductor fault level rating	Conductor thermal rating	Voltage limits	Conductor capital cost	Technical losses	Non-technical losses	Changes in utility revenue due to conductor voltage drop
IEC 287-3-2 [1995]	Note 1	Note 1	Note 1	✓	✓		
Willis [1997]		✓	✓	✓	✓		
Sellick [1999]	Note 2	Note 2	✓	✓	✓		
Curcic et al [2001]				✓	✓		
Mandal and Pahwa [2002]		✓	✓	✓	✓		
Falaghi et al [2005]		✓	✓	✓	✓		
Proposed method		✓	✓	✓	✓	✓	✓

Table 3.2.2: Components included for conductor size optimisation

Note 1: The IEC 287-3-2 [1995] bases conductor size optimisation on the minimisation of the sum of the initial installation cost and the lifetime cost of technical losses. Fault level ratings, thermal ratings and voltage limits are not explicitly included in the conductor size optimisation. The IEC 287-3-2 states that these additional criteria should be considered in addition to the economic conductor size (based on initial and lifetime technical loss costs).

Note 2: Using the same approach as the IEC 287-3-2 [1995], Sellick [1999] states that in addition to the economic conductor size, fault level ratings and thermal ratings also need to be considered, but are not explicitly included in the conductor size optimisation.

As per IEC 287-3-2 [1995] and Sellick [1999], the calculation of the economic conductor size can be considered a minimum conductor size. Additional constraints (such as fault level ratings) possibly resulting in larger conductor sizes can be included by ensuring that the optimal conductor size also meets these constraints. The assessment of these additional constraints can hence be performed as a separate step following the economic conductor size optimisation. Additional constraints, such as conductor fault level rating, could be included in the proposed method for application in other networks/countries where consideration of these additional constraints is necessary.

The proposed method includes non-technical losses and changes in utility revenue due to conductor voltage drop. This is novel, and the relevance needs to be established.

### 3.3 CONDUCTOR SIZE OPTIMISATION OBJECTIVE

For the purposes of the research there are two conceptual alternatives for the modelling of utility cost and revenue for conductor size optimisation:

- 1) **Model all costs and revenues:** All lifetime costs and lifetime revenues are modelled. The lifetime net profit is the lifetime revenue minus the lifetime cost. The optimal conductor size maximises the lifetime net profit. This analysis can also give an indication of expected Return On Investment (ROI), but requires that all costs and incomes are included.
- 2) **Model changes in costs and revenue:** Only significant changes in lifetime cost and significant changes in lifetime revenue are modelled. Changes are relative to one of the alternatives, henceforth referred to as the base alternative. An increase or reduction in cost (as compared to the base alternative) is reflected as a positive or negative cost respectively. A reduction or increase in revenue (as compared to the base alternative) is reflected as a positive or negative missed opportunity cost respectively. The optimal conductor size minimises the sum of the change in cost and missed opportunity cost. This analysis does not give an indication of expected ROI.

A ROI calculation is not required for this research. The 2<sup>nd</sup> alternative is preferred as it requires less data. The "base alternative" for the purposes of the comparison of conductor costs is a fictitious ideal conductor with zero cost and zero impedance. An "ideal" conductor is used as the calculated difference in cost for a particular conductor size is the cost associated with that conductor for the components considered in the analysis.

The cost components identified in tables 3.2.1a, 3.2.1b and 3.2.1c for inclusion in the proposed method are optimised by minimising the sum of the cost components in table 3.3.1.

Cost component	Cost relative to	Range of values	Polarity description
Conductor capital cost in initial year [Rand]	Conductor with zero capital cost	0, +ve	+ve: Increase in utility capital = cost
Present value lifetime increase in utility bulk energy purchase costs due to conductor technical losses and changes in customer energy consumption and demand due to conductor voltage drop [Rand]	Conductor with zero impedance	+ve, 0, -ve	+ve: Increase in lifetime utility bulk energy purchase cost = cost -ve: Reduction in lifetime utility bulk energy purchase cost = reduction in cost
Present value lifetime decrease in revenue due to changes in customer energy consumption and demand due to conductor voltage drop [Rand]	Conductor with zero impedance	+ve, 0, -ve	+ve: Reduction in lifetime customer energy consumption = decrease in revenue = equivalent to cost -ve: Increase in lifetime customer energy consumption = increase in revenue = equivalent to a reduction in cost

Table 3.3.1: Cost components for conductor size optimisation for minimum lifetime cost

The customer energy consumption and demand referred to in table 3.3.1 include non-technical losses. Non-technical losses may impact on bulk purchases, technical losses and revenue, and will be included in the optimisation.

It is convenient for subsequent chapters if the optimisation objective is referred to as lifetime cost minimisation, with the understanding that changes in revenue are included whereby a reduction in revenue (due to conductor voltage drop) is considered a missed opportunity cost.

Conductor size optimisation is performed by minimising the lifetime capital, technical load loss and voltage drop costs, within the constraints of conductor thermal ratings. Technical load loss and voltage drop costs reflect the changes in utility bulk energy purchase costs and utility revenue due to conductor impedance.

The voltage drop (and hence consumer voltages) associated with the optimal conductor size need to be calculated. The optimisation will not be constrained by voltage drop limits or voltage limits.

### 3.4 PRACTICAL APPLICATION

The method should be applicable to South Africa and other countries where distribution networks are operated radially.

Demonstration of the method will be confined to South African technologies and applications. Costs (capital and losses) and financial parameters will be based on Eskom values.

### 3.5 LOOKING FORWARD

The following components need further investigation:

- Calculation and assessment of MV and LV voltage drop.
- Calculation and costing of conductor technical losses.
- Calculation and costing of changes in utility bulk energy purchase costs and changes in utility customer revenue for different conductor sizes.
- Optimisation of conductor size to minimise lifetime costs within conductor thermal constraints.

A possible reduction in lifetime cost via the proposed method as compared to the present philosophy of minimum initial capital cost needs to be assessed for South African rural domestic electrification.

## 4. VOLTAGE DROP ASSESSMENT

Domestic consumers take supply at the LV service voltage. LV service voltages depend on the voltage drops in the MV networks, MV/LV transformers and LV networks. For the purposes of this research, the assessment of the MV and LV network and MV/LV transformer voltage drops is required.

In this chapter the criterion for voltage assessment is introduced, with focus on South African standards. LV voltage drop calculation methods are investigated, as appropriate for stochastic domestic loads. MV voltage drop calculation is discussed, with emphasis on the different requirements for MV as compared to LV networks. Recommendations are made for further investigation and testing.

### 4.1 VOLTAGE COMPATIBILITY LEVELS

The minimum LV voltage performance is usually specified as a maximum and minimum voltage [IEC 38, 1994; ANSI C84.1, 1995; DME, 1996]. ANSI C84.1 [1995] specifies two ranges of voltage limits as follows:

Range	Voltage limits	Comments
A	±5%	Most service voltages must be within these limits.
B	+5.83% - 8.33%	Additional voltage variations due to practical design or operating conditions. Must be limited in extent, frequency and duration.

Table 4.1.1: ANSI C84.1 [1995] 120V service voltage limits (Northern America)

South African LV voltage limits are specified in government regulations [DME, 1996] and align with IEC 38 [1994]. The LV voltage at the point of supply can vary by ±10% of the nominal value (400/230V). There is no differentiation between normal and abnormal voltage limits.

The above standards [IEC 38, 1994; ANSI C84.1, 1995; DME, 1996] do not specify how the voltage should be assessed (the voltage performance criterion). The South African voltage

performance criterion is prescribed in the NRS 048-2 [2004], which is similar to the Euro Norm EN 50160 [2000]. The NRS 048-2 [2004] specification for LV customers <500V is as follows:

- The standard LV voltage is 400V phase to phase (three phase Star), and 230V phase to neutral (single phase and bi-phase). Voltage assessment is performed on the phase to neutral voltages.
- The assessment period is at least one week. For long-term measurements, the assessed weekly value is retained on a daily sliding basis.
- The highest and lowest of the assessed 95 % weekly values over the full measurement period must not be outside 230V  $\pm$ 10%.
- Not more than two consecutive 10-minute values can exceed 230V +10%, and not more than two consecutive 10-minute values can be less than 230V -10%.
- The maximum deviation of the 10-minute values from 230V over the full measurement period cannot exceed 230V  $\pm$ 15%.

As will be shown, the method used for voltage drop calculation depends on the network and load characteristic, and voltage performance criterion.

## 4.2 LV VOLTAGE DROP

In LV networks supplying relatively few customers the errors in voltage drop calculations can be large due to inadequate treatment of the stochastic nature of the load [Sellick and Gaunt, 1995]. This section focus on the calculation of LV voltage drops for stochastic loads, with specific focus on domestic loads.

In an analysis of the requirements of LV domestic design guidelines, Herman [1992] highlights the following key aspects that are relevant to this research:

- Load currents vary stochastically, and this stochastic nature must be accounted for in both phase and neutral current calculation.
- The design philosophy needs to be standardised with a logical procedure for application.
- Load estimation should be based on the selection of a consumer class, and any other parameters that have an affect on the consumer class.
- It is necessary to consider probability and confidence limits in design calculations due to the statistical nature of the loads.

SABS 0150 [1983, subsequently withdrawn] and Swanepoel [1989] use diversity and unbalance factors to adjust balanced LV load-flow voltage drops to account for the impact of varying domestic customer numbers on load diversity and unbalance. Formulae/adjustment factors are based on the inspection of load research data or assumed Gaussian distributions at the period of maximum loading. Techniques based on the inspection of load research data are not probabilistic and do not account for risk.

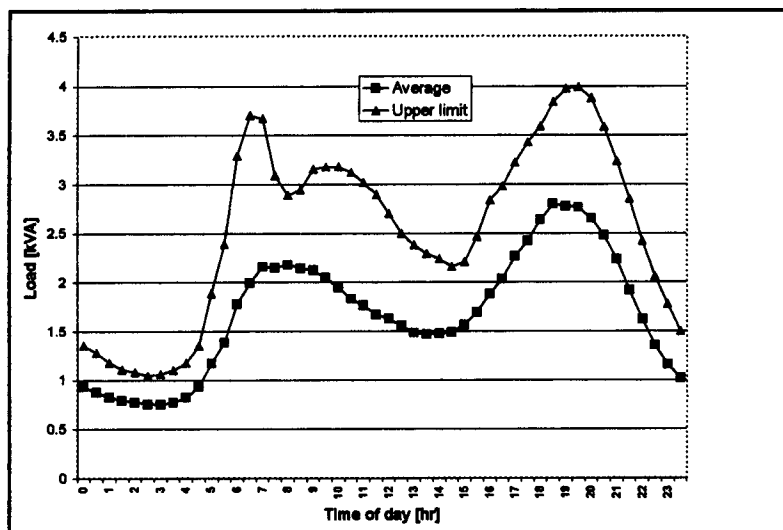
#### 4.2.1 Herman Beta voltage drop assessment

Figure 4.2.1.1 shows a typical winter weekday load profile for Claremont measured in 1997 [Heunis and Herman, 1999b]. Two curves are plotted on the graph:

- An average load curve: The average load for the community during winter months.
- An upper limit load curve: The maximum average load which can be expected for a specific half-hour period.

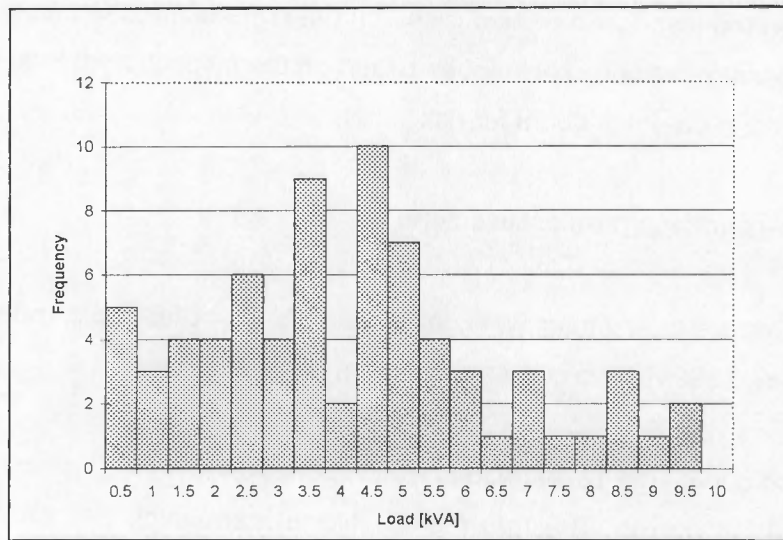
The extreme of the upper limit curve is equal to the ADMD of the community. Claremont registered an ADMD of 4 kVA in 1997 [Heunis and Herman, 1999b].

Figure 4.2.1.1: Typical winter weekday load profile for Claremont as measured in 1997 [Heunis and Herman, 1999b]



The ADMD is the maximum average load of a number of consumers. Figure 4.2.1.2 shows a histogram of the individual loads when the average load is a maximum and illustrates that the load currents at the instant of system maximum demand vary significantly.

Figure 4.2.1.2: A histogram of the individual loads (Claremont 1997) at the moment when the average load is a maximum [Heunis and Herman, 1999b]



Using the results of the first synchronised recordings of individual South African domestic customers during peak loading, Herman and Gaunt [1991] identify “*that the load distribution is significantly different from a Gaussian distribution.*” In further research Herman [1993a] and Herman and Kritzingler [1993] establish that for South African domestic consumers the most appropriate probability density function for peak load current is the beta probability distribution function (hereafter referred to as a beta distribution).

Herman [1993b] develops a probabilistic method to predict the voltage drop in domestic LV feeders, using a beta distribution load current model. The method, which has been termed the “*Herman Beta*” method [NRS 034-1, 1999], manipulates the load current distribution into a consumer voltage distribution. The transformation is achieved by combining the first and second moments of the load current distribution in ratios determined by the connection arrangement of the feeder. The result is the first and second moment of the consumer voltage random variable. A beta distribution is fitted (using the first and second moments of the consumer voltage random variable) to obtain a consumer voltage distribution (consult the NRS 034-1 [1999] for details of the Herman Beta method). The calculated consumer voltage is a range of values and each value has an associated probability. The voltage drop design criterion is a deterministic limit e.g. 10% [NRS 034-1, 1999; Carter-Brown and Gaunt, 2006b; Sellick, 1999]. The range of possible values can only be evaluated if one of the values in the predicted range of voltage values is chosen. This is achieved by selecting a confidence level and obtaining the associated percentile value.

The load model used in the Herman Beta method is similar to the load models used in the probabilistic load-flow analysis as developed by Allan et al [1974] and Caramia et al [1999]. These models assume that the load parameters of specific consumers are known. In residential communities this is not the case [Herman and Heunis, 2002]. The load characteristics of a homogeneous load class may be established via load research, but the characteristics of individual consumers in practical network design is unknown (aerial photographs of un-serviced areas can give some indication of the shape and size of dwelling, but very little else) [Herman and Heunis, 2002].

Sellick and Gaunt [1995] compare different LV voltage drop calculation methods and conclude that the Herman Beta method most accurately estimates the voltage drop (at peak loading) for different network topologies, customer connections and load models (skewness of the current distribution).

Heunis [1997] enhances the original Herman Beta method via superposition to address the errors introduced by successive risk in multi branch networks.

The Herman Beta method, as enhanced by Heunis [1997], is endorsed by the NRS 034-1 [1999] as the recommended method for LV domestic voltage drop calculations in South Africa. NRS 034-1 [1999] provides details on the Herman Beta calculations, and benchmark cases for the testing of the algorithm in software applications.

Due to convenience, the beta distribution parameters of load current are typically based on the consumer circuit breaker rating, ADMD and standard deviation of the consumer currents at the ADMD [Gaunt, 1999].

Analysis of the South African NRS domestic load research data concluded that the load current ADMD and variance at peak are strongly correlated to the After Diversity Demand (ADD, which is the average consumer load current over an extended time period such as a month) [Heunis and Dekenah, 2001]. The ADD is in turn strongly correlated to the household income, time with electricity and Climatic Severity Index (CSI, based on the climatic regions in South Africa) [Heunis and Dekenah, 2001]. These relationships have been incorporated into a software tool for ADMD, monthly energy consumption and beta parameter estimation [Heunis and Dekenah, 2001].

As the Herman Beta method accurately models the effects of unbalanced customer phase connections [Sellick and Gaunt, 1995], the implications of different balancing approaches

can be determined [Herman et al, 1998]. The results are very significant and Herman et al [1998] show that for the same conductor volume a benchmark three phase and bi-phase LV feeder give similar voltage drop performance. This is significant as an appropriate voltage drop calculation method can radically change design beliefs that may be based on inappropriate assumptions. For the purposes of this research it is important to note that the design may be very sensitive to the voltage drop calculation method used.

It is interesting to note that in networks with few (typically less than 10) customers the maximum voltage drop may not necessarily occur during peak mean loading [Gaunt, 1999]. A method that provides for the calculation of voltages at different times and loading conditions is desirable.

Herman [2001a], Herman [2001b] and Herman and Heunis [2003] further enhance the Herman Beta method to cater for mixtures of loads, fixed loads and optimised phase connection (to minimise voltage drop).

The Herman Beta method only considers network resistance (inductance is ignored) and assumes that the loads are constant current with unity power factor. These limitations and assumptions are considered to be valid for the assessment of LV residential voltage drop [Herman, 1993b; Gaunt et al, 1999]. The likely error range due to these assumptions needs to be established (see section 9.4).

As mentioned previously, the range of probable voltage values provided by the Herman Beta method is evaluated by selecting a confidence level and obtaining the associated percentile value of the consumer voltage distribution. The probability of measuring a LV voltage at peak load that is greater than the percentile value is known as the confidence level (reduced voltage drop results in increased voltage). The probability of measuring a LV voltage at peak load that is lower than the percentile value is known as the risk (increased voltage drop results in reduced voltage). The design risk is the probability of exceeding the design percentile value.

In South Africa a design risk of 10% has historically been used [NRS 034-1, 1999]. The basis for this design risk is that this choice will result in designs that are not as expensive as compared to a 1% or 5% design risk [Heunis, 1997].

A 10% design risk does not mean that at the feeder peak loading the minimum voltage on the feeder will be above the design minimum value for 90% of the time. It should rather be

interpreted as 90% of the feeders will have a minimum voltage greater than the design minimum value at the time of the peak load.

#### 4.2.2 QOS voltage drop assessment

The Herman Beta method only considers the load at one instant in time and the design risk applies to this instant in time. The consumer load currents at peak are statistically independent [Heunis, 2000].

Consumer load currents considered over time are statistically dependent (correlated), and this can be seen in the well known residential load profiles for different day types (weekday, Saturday and Sunday), seasons (winter, spring, summer, autumn) and load growth [Heunis, 2000]. Load currents are correlated due to external (weather) and internal (habits) which influence the use of appliances [Heunis, 2000].

Figure 4.2.2.1: Average load profile as measured in two consecutive days in Tambo during 1998 [Heunis and Herman, 2000]

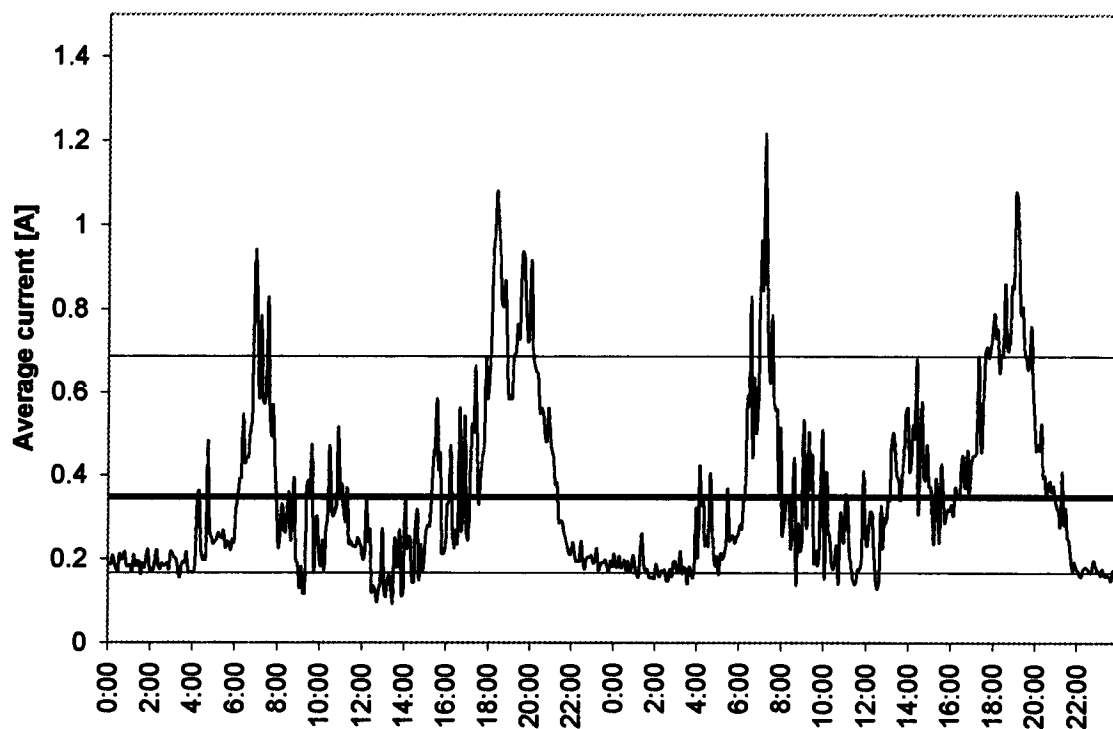


Figure 4.2.2.1 shows the average load current trace for two consecutive days as measured in Tambo, South Africa in 1998 [Heunis and Herman, 2000]. The trace has a mean value (indicated by the bold horizontal line) and a movement away from the mean. This movement

can be measured as the standard deviation of the trace. The two thin horizontal lines show the 10<sup>th</sup> percentile and 90<sup>th</sup> percentile of the trace.

As can be observed in figure 4.2.2.1, Heunis [1997] identifies that numerous load peaks of similar magnitude are likely to occur in residential feeders. There are two implications for voltage drop assessment:

- The ADMD is uncertain. The Herman Beta method requires a description of the load at peak. There is uncertainty in the peak load and this is complicated by the consideration of events such as extreme temperature variations.
- The probability of exceeding the design percentile voltage drop is increased when the same, or similar, peak load repeats over time. In South Africa the QOS risk is defined as the probability that a feeder will violate the NRS 048-2 [2004] voltage performance criterion.

Heunis and Herman [1999b] investigate uncertainty and uncertainty models for the design of LV residential feeders, and via Monte Carlo simulation identify that there is a significant difference between the design risk and voltage QOS risk for South African network and consumer characteristics. Heunis [2000] develops a load model and associated voltage drop calculation for QOS voltage assessment. The method is similar to the Herman Beta method as the consumer voltage is fitted to a Beta distribution using the connection arrangement of the feeder. However the first and second moments of the consumer voltage are calculated based on a range of expected load parameters, considering the correlation of load currents over time. The expected maximum load current is calculated as a percentile value, thereby quantifying the probability in the selection of the maximum load (and hence the effect of abnormal load peaks such those caused by extreme temperature variations).

Initial testing of the QOS method shows that the method is a better predictor of QOS voltage performance as compared to the Herman Beta method [Heunis, 2000]. Furthermore it appears that there is no obvious correlation between design risk and QOS risk [Heunis and Herman, 2001].

The QOS method is being assessed by Eskom Distribution for possible replacement of the Herman Beta method [Heunis and Herman, 2001; Lakmeharan and Heunis, 2001; Heunis, 2002; Heunis, 2003].

The QOS and Herman Beta methods are similar in that they are both based on beta load current models, and via superposition, can accommodate fixed loads and mixed domestic loads. The methods have the same assumptions and limitations regarding network reactance (ignored), load power factor (unity) and load voltage dependency (constant current).

The LV voltage drop calculation (Herman Beta or QOS) implemented in this research depends on the following requirements:

- Loss and voltage drop calculations should, as far as possible, share the same load data.
- The voltage drop calculation and data requirements should be applicable for analysis at all time intervals (not just peak) and with a range of load types such as schools, clinics and shops (in addition to domestic consumers).

#### 4.2.3 Monte Carlo simulation

Oliveira et al [2005] utilise Monte Carlo simulation to extract LV percentile voltages for the probabilistic analysis of LV network voltage variation. This approach is calculation intensive, and is unnecessary as the QOS voltage drop calculation method calculates the percentile voltages using probabilistic calculations.

Thomson and Infield [2005] utilise customer load models based on 1 minute time intervals. For each study the 1 minute loads at each customer are generated based on the load model. The consumer loads vary for each study. To extract probabilistic results these studies would need to be repeated via Monte Carlo analysis. The simulation of a 3700 node network over a single day took 20 minutes. Repeating the analysis 1000 times (to derive percentile values) would take 14 days!

Monte Carlo simulation is essential for the testing of probabilistic calculation methods, but is not suitable for practical network planning and design. For the purposes of this research, Monte Carlo simulation will be confined to the testing of proposed methods only.

## 4.3 MV VOLTAGE DROP

### 4.3.1 Deterministic techniques

Deterministic voltage drop calculations are well described [Willis, 1997; Brice, 1992]. Research into South African domestic voltage drop estimation is focused on the LV networks, where the stochastic nature of the load results in large errors with deterministic voltage drop calculations [Sellick and Gaunt, 1995]. Deterministic MV voltage drop calculations have historically been used for the following reasons:

- South African domestic electrification MV network branches typically supply more than 100 customers. As will be shown (section 4.3.2), the coefficient of variation of the load reduces as the number of customers increases. Errors (due to the stochastic load characteristic) in deterministic calculations are expected to be sufficiently small for practical MV network planning and design voltage drop calculation purposes.
- In overhead MV networks the conductor spacing, and hence reactance, is larger than for LV networks. MV voltage drops are expected to be more sensitive to network reactance and load power factor (as compared to LV networks), and needs to be tested. Network reactance, load power factor and load voltage dependency are considered by deterministic load-flow techniques.
- Deterministic techniques are widely available in commercial and utility load-flow software.

The advantages of deterministic MV voltage drop calculation techniques appear to outweigh the advantages of present probabilistic techniques. However the expected error levels in deterministic techniques need to be quantified so that their suitability can be assessed for this research.

Deterministic MV and probabilistic LV voltage drop calculations are presently combined in a typical South African domestic electrification network study as follows:

- 1) The probabilistic current/load is calculated at the LV terminals of each distribution transformer using the probabilistic LV load model (Herman Beta or QOS). For the purposes of MV network and MV/LV transformer load-flow, this load is converted into a fixed load on the LV terminals of the distribution transformer.
- 2) Deterministic MV load-flow is performed with the transformer fixed loads. Load voltage dependency, power factor and network reactance are considered by the deterministic calculations.

- 3) The calculated voltage at the LV terminals of each distribution transformer is the source voltage for the respective LV network.
- 4) The LV voltage drop, and hence minimum LV voltage, is calculated using probabilistic LV load-flow (Herman Beta or QOS methods).

Repo et al [2005] use the same approach for MV voltage drop analysis as described above, however the LV loads are based on normal distributions.

#### 4.3.2 Preliminary analysis of error levels in deterministic techniques

Domestic loads are not correlated at a single time instance, such as peak loading. As the number of consumers increases so the coefficient of variation decreases. This is demonstrated in table 4.3.2.1 for the NRS 034-1 [1999] "rural village" load class for the year 7 peak loading. The normalised 90<sup>th</sup> percentile current was calculated as the 90<sup>th</sup> percentile current using beta and normal distributions, divided by the number of consumers. The expected error in the 90<sup>th</sup> percentile current for 1000 customers if the current is based on the non-statistical addition of the percentile currents for smaller numbers of consumers is calculated i.e. the expected error if the percentile currents at the MV/LV transformers are represented as fixed loads for MV load-flow analysis. The difference between the 90<sup>th</sup> percentile currents based on beta and normal distributions is also calculated.

Number of consumers N	Mean $\mu$ [amps]	Standard deviation $\sigma$ [amps]	Coefficient of variation $\sigma/\mu$	Normalised 90 <sup>th</sup> percentile beta/normal current [amps]	Difference between normal and beta 90 <sup>th</sup> percentile currents	Beta current error relative to 1000 consumers
1	3.00	3.60	1.20	8.40 / 7.63	-9.21%	166.95%
5	15.00	8.05	0.54	5.21 / 5.07	-2.64%	65.45%
10	30.00	11.38	0.38	4.53 / 4.46	-1.48%	43.96%
50	150.00	25.46	0.17	3.67 / 3.65	-0.35%	16.54%
100	300.00	36.00	0.12	3.47 / 3.46	-0.18%	10.23%
250	750.00	56.92	0.08	3.29 / 3.29	-0.07%	4.71%
500	1500.00	80.50	0.05	3.21 / 3.21	-0.03%	1.94%
1000	3000.00	113.84	0.04	3.15 / 3.15	-0.01%	0.00%

Table 4.3.2.1: Load characteristic sensitivity to customer numbers at peak loading for the rural village customer load class according to NRS 034-1 [1999]

As expected (as a consequence of the central limit theorem), the difference in the 90<sup>th</sup> percentile normal and beta distribution currents decreases with increasing customer numbers. Errors between normal and beta distribution load models are negligible for customer numbers in excess of 50. This indicates that if a probabilistic MV load-flow is required, normal distributions are adequate for MV network analysis.

In voltage limited networks the majority of the MV voltage drop occurs in the MV primary (that part of a MV distribution feeder supplying the bulk of the load) [Van Wormer, 1954]. In South African domestic electrification the number of customers supplied by the MV primary typically exceeds 250. Table 4.3.2.1 indicates that the MV primary voltage drop error levels may exceed 16% if domestic loads are modelled as undiversified fixed loads at each MV/LV transformer location, where the number of consumers supplied per transformer is less than 50. The method used by Repo et al [2005] also overstates the load as the loads are not diversified in the MV load-flow calculations.

Three deterministic MV load-flow options need to be evaluated:

1. Undiversified MV loads: The entire MV network is modelled, including MV laterals (the MV lateral is typically a tee line off the MV primary). The MV/LV distribution transformer loads are modelled as "bulk" loads at the MV terminals of the distribution transformers. The MV bulk load at each distribution transformer is based on the load mean and variance for the number of customers supplied by that distribution transformer (MV bulk loads are not diversified). This is expected to overstate the total MV voltage drop (the load and voltage drop in the MV primary will be overstated).
2. Diversified MV loads: The entire MV network is modelled, including MV laterals. The MV bulk load at each distribution transformer is based on the normalised load mean and variance for the number of customers supplied by the entire MV network (MV bulk loads are diversified) multiplied by the number of customers supplied by that distribution transformer. This is expected to understate the total MV voltage drop (load and voltage drop in MV laterals will be understated). The error level in the total MV voltage drop may however be low as the voltage drop in the MV laterals is typically much less than the voltage drop in the MV primary (the MV lateral voltage drop is typically a 3<sup>rd</sup> of the MV primary voltage drop in voltage limited feeders [Van Wormer, 1954]).
3. Undiversified loads lumped onto MV laterals: MV lateral line loadings are lumped onto the MV primary as MV bulk loads, where each MV bulk load is calculated based on the load mean and variance for the number of customers supplied by that MV lateral. Only the MV network between the MV source and MV lateral with expected minimum MV voltage is modelled. This method is expected to overstate the total MV voltage drop (South African domestic electrification MV laterals typically supply less than 250 consumers and the MV bulk loads will hence be overstated) but the error will be less than for option 1. The disadvantage of this option is that the expected voltage at the end of all MV laterals is not calculated in a single study.

A probabilistic MV load-flow technique should only be investigated as part of this research if the error levels in the above options exceed practical planning and design requirements. A marginal improvement in accuracy may require considerable additional complexity and should be carefully assessed.

Note that the MV/LV distribution transformer loadings and voltage drops should be assessed as part of the LV network modelling so that the diversity at the distribution transformer level is appropriately modelled.

#### 4.4 LOOKING FORWARD

Methods are required for the calculation of South African domestic electrification MV and LV network and MV/LV transformer voltage drops. The voltage drop calculation methods need to take into consideration the way voltage performance is assessed in South Africa.

A probabilistic LV voltage drop calculation is required that accounts for varying customer numbers, load diversity and unbalance:

- The Herman Beta and QOS methods are based on a beta distribution of consumer load currents.
- The Herman Beta and QOS voltage drop methods use the same assumptions/simplifications that network reactance is ignored, load power factor is unity and loads are constant current. The possible errors associated with these assumptions/simplifications needs to be established.
- The calculations need to be tested via Monte Carlo simulation using South African load research data.

The LV voltage drop calculation implemented in this research (Herman Beta or QOS method) will depend on the following requirements:

- Loss and voltage drop calculations should, as far as possible, share the same load data.
- The voltage drop calculation and data requirements should be applicable for analysis at all time intervals (not just peak) and with a range of load types such as schools, clinics and shops (in addition to domestic consumers).

A new probabilistic LV voltage drop calculation method should only be investigated if the Herman Beta or QOS methods (with possible modification or enhancement) do not provide acceptable accuracy.

Deterministic MV voltage drop calculation may result in acceptable accuracy in South African domestic electrification. Three deterministic MV voltage drop calculation options have been identified for further testing.

A probabilistic MV load-flow technique should only be investigated if the error levels in the deterministic MV voltage drop calculation options exceed practical planning and design requirements.

## **5. TECHNICAL LOSSES CALCULATION AND COSTING**

Technical loss is an important lifetime cost component. Methods for the calculation and costing of technical losses are required for conductor size optimisation.

This chapter begins by introducing technical and non-technical losses. The main characteristics of technical loss estimation and costing for planning and design purposes are summarised. Different technical loss calculation techniques are discussed, noting data requirements, advantages, disadvantages and limitations. Promising techniques are identified for further consideration. Methods for the costing of technical losses are analysed, and desirable qualities established. Technical loss assessment methods for distribution network planning and design are reviewed, with emphasis on methods for conductor size optimisation.

### **5.1 INTRODUCTION TO DISTRIBUTION TECHNICAL LOSSES**

#### **5.1.1 Technical and non-technical losses**

Distribution network losses are traditionally split into two categories; technical and non-technical losses [Davidson et al, 2002; Cespedes et al, 1983; Saenz et al, 2001].

Load and no-load losses are referred to as technical losses. Bacelar [1995] observes that in distribution networks:

- Load losses arise due to  $I^2R$  copper losses in components such as lines and transformers. The load loss is responsible for the majority of technical losses. This is supported by Tobin and Glynn [1991].
- No-load losses are predominately due to core magnetization and usually vary with the square of the applied voltage.

- Losses due to joints, corona and leakage currents are so small that they are usually considered to be insignificant.

In transmission and sub-transmission HV network loss calculations, corona losses are included, but are considered insignificant in distribution technical loss evaluations [Cespedes et al, 1983].

Non-technical losses are also referred to as “black losses” and are predominately due to de-calibration of meters, bypassing of meters, damaged meters, errors and estimations in the billing system, and energy theft due to customers not registered in the billing system [Cespedes et al, 1983; Davidson et al, 2002].

Technical losses are dependent on the physical characteristics of the network (voltage levels, line lengths, line technology and conductor size), equipment specification (impedances, no-load losses) and the characteristics of the load (magnitude, power factor and Load Factor) [Hickok, 1978; Cespedes et al, 1983; Flaten, 1988; Grainger and Kendrew, 1989; Willis, 1997; Vujosevic et al, 1999; Oliveira et al, 2001; Davidson et al, 2002]. Operations including normally open points, voltage control settings, tap settings, and load balancing influence branch load currents and hence technical losses [Tobin and Glynn, 1991; Davidson et al, 2002]. Operational decisions will impact technical losses, however the majority of losses are determined by the network’s physical characteristic, which is established at the planning and design phase.

Davidson et al [2002] consider technical losses in the context of a “de-regulated” (not vertically integrated) Electricity Supply Industry, and observe that:

- *“Losses represent a considerable operating cost, estimating to add 6-8% to the cost of electricity and some 25% to the cost of delivery”.* Technical losses do not have immediate regulatory implications, but need to be managed and optimized.
- Historically there has been little focus on the management of distribution technical losses as *“they [technical losses] do not constitute major operational or quality of supply problems.”*

In outlining the approach for evaluating distribution losses at the Electricity Supply Board, Ireland, Tobin and Glynn [1991] state that *“Losses are intrinsic to the process of power delivery but can be reduced to an economically optimal level. They are a significant factor in*

*planning and system improvement. Policy on losses can substantially shape the structure and development of a distribution system."*

#### 5.1.2 Loss assessment for network planning and design

Based on the work by Flinn et al [1983], Cespedes et al [1983], Flaten [1988], Bacelar [1995], Vujosevic et al [1999], Sellick [1999], Ferreyra and Paoletich [2001] and Oliveira et al [2001] the main characteristics of loss estimation and costing for planning and design purposes are as follows:

- The losses are only of interest in the components that the planner/designer/operator can influence.
- Analysis ignores the losses in system components that are not directly influenced by a local decision e.g. when selecting the size of a MV conductor, the losses in the downstream transformers and LV network can be ignored if their design and loads are not significantly influenced by the choice of MV conductor.
- Non-technical losses are considered to be independent of the network alternatives [Sellick, 1999], but allowances for non-technical losses may be required in load models.
- The analysis is complicated by the requirement to calculate both the magnitude and cost of technical losses, including future load and generation impacts. Planning and design studies require an economic analysis of losses, in an environment where there may be considerable uncertainty associated with key parameters, especially forecasted load.
- Methods differ due to different network characteristics, data availability and the accuracy requirement.

The rated losses of network devices are provided in manufacturer specifications [Hickok, 1978], but are only applicable for a specific (usually rated) loading level. Technical load loss estimation is complicated by the requirement to account for load variations over the evaluation period. This led Wood [1958] to make the observation that "*The determination of electrical losses is an important feature in the economics of any distribution network and, due to many factors that may only be approximated, it is one which tends to be very complex.*" The "many factors" referred to by Wood [1958] are expanded upon by Vujosevic et al [1999] to include the complex structure of the distribution network, and large and unreliable network and load databases.

## 5.2 CALCULATION OF TECHNICAL LOSSES

### 5.2.1 No-load losses

The no-load loss is almost entirely due to iron loss (hysteresis and eddy current) in transformer cores [Bacelar, 1995].

Due to core saturation the no-load losses are sensitive to the magnitude of the applied voltage. It is commonly assumed that the average core loss is the rated core loss at rated voltage [Tobin and Glynn, 1991], unless there are known operational differences in which case specific studies are recommended [Bacelar, 1995], and load-flow analysis is required to calculate busbar voltages [Nazarko et al, 2000]. For the purposes of this research no-load losses are assumed to be constant. The no-load loss demand is obtained by summing the rated core loss of transformers. The no-load loss energy is obtained by multiplying the no-load loss demand with the number of hours in the evaluation period.

### 5.2.2 Load Losses: Loss Load Factor

It is common practice to simulate the network peak load condition for the assessment of thermal limits, voltage drop and technical load losses. The Loss Load Factor (LLF) is extensively used [Nickel and Braunstein, 1981; Cespedes et al, 1983; Flinn et al, 1983; Baylor and Gustafson, 1989; Grainger and Kendrew, 1989; Bacelar, 1995; NRS 034-1, 1999; Sellick, 1999; Davidson et al, 2002; Falaghi et al, 2005] to describe the relationship between the average load loss and the maximum load loss (at peak load) and is mathematically expressed as follows:

$$LLF = \frac{\text{Avg load loss}}{\text{Max load loss}} \quad 5.2.2.1$$

LLF	Loss Load Factor [per-unit]
Avg load loss	Average load loss in time period [kW]
Max load loss	Maximum load loss in time period [kW]

The load loss energy over a time period is expressed as:

$$\text{Load loss energy} = \text{Max load loss} \cdot \text{LLF} \cdot \text{Eval period} \quad 5.2.2.2$$

Load loss energy      Load loss energy over evaluation period [kWh]

Eval period              Time in evaluation period [hours]

The Loss Load Factor is dependent on the characteristic of the load. Buller and Woodrow first quantified a relationship between the Loss Load Factor and Load Factor (LF) in the late 1920s [Baylor and Gustafson, 1989]:

$$\text{LLF} = X \cdot \text{LF} + (1 - X) \cdot \text{LF}^2 \quad 5.2.2.3$$

X      A constant dependent on the load characteristic, and is derived empirically

LF      Ratio of the average demand to the maximum demand (within a period) and is expressed as:

$$\text{LF} = \frac{\text{Avg demand}}{\text{Max demand}} \quad 5.2.2.4$$

Avg demand              Average load demand in time period [kW]

Max demand              Maximum load demand in time period [kW]

Baylor and Gustafson [1989] show that the optimal value of X for modern (1989) American load shapes is typically below 0.1, and recommended the use of X = 0.08.

A second equation is also commonly used to express the Loss Load Factor as a function of Load Factor [Baylor and Gustafson, 1989; Bacelar, 1995]:

$$\text{LLF} = \text{LF}^\alpha \quad 5.2.2.5$$

$\alpha$       A constant that typically varies between 1.55 and 1.80 [Bacelar, 1995]

The following issues and limitations associated with the Loss Load Factor method must be noted:

- Bacelar [1995] identifies that the accuracy of the Loss Load Factor (as calculated via equations 5.2.2.3 or 5.2.2.5) *“depend to a great degree on the power factor, since the load factor used is based on the active power and the values of X and  $\alpha$  are empirically estimated from apparent power load cycles.”* A technique that incorporates the impact of the power factor of the load in loss calculations will improve accuracy and should be considered for this research.
- Wood [1958] identifies that the Load Factor and Loss Load Factor are a function of the number of consumers. Sellick [1999] derives Load Factor and Loss Load Factor values from load research data for domestic communities in South Africa. The results of the Helderberg community are as follows. As the number of consumers increased from one to sixty one, the Load Factor increased from 9% to 26%. The Loss Load Factor increased from 2.5% to 8%. Beyond approximately 40 customers there is no appreciable change in the Load Factor and Loss Load Factor. For the purposes of this research, loss analysis in networks supplying stochastic domestic loads should account for the impact of varying customer numbers.
- Michie [1992] observes that the decrease in Load Factor towards the end of the feeder is due to the loss of diversity as the number of customers decreases. In networks supplying domestic loads the Load Factor and Loss Load Factor vary for each branch due to differences in customer numbers [Sellick, 1999]. Techniques such as those employed by Cespedes et al [1983] and Flinn et al [1983] exclude the effects of load diversity as a single Loss Load Factor is used per customer type, regardless of the number of customers. The errors may be significant. For the purposes of this research, diversity should be included by calculating losses separately for each branch. This is very convenient if thermal loading and voltage drop calculation techniques also require a per branch analysis (as is the case with the Herman Beta and QOS methods discussed in chapter 4).
- The balancing of load connections influences the peak current, Load Factor and Loss Load Factor in each phase (the customer numbers supplied by individual phases change). The dynamic nature of unbalance (which varies with load cycles) is not taken into consideration by the Loss Load Factor. For the purposes of this research, the effect of load balancing at peak and other time periods should be included in loss calculations.
- It is assumed that the loads vary uniformly at all busses [Bacelar, 1995] i.e. that the loads are homogeneous and have the same load shape, and in future years change at the same rate. For the purposes of this research, loss calculations should be able to cater for

networks supplying mixtures of loads with different load shapes (non-homogeneous loads) and different load forecasts.

- The accuracy of the Loss Load Factor technique is dependent on the maximum load used in studies. Due to the stochastic nature of distribution loads, the maximum loading of a network can be difficult to quantify and should be represented as a statistical property associated with a confidence level [Herman, 1993b] i.e. a maximum load value with a certain probability that this value will not be exceeded. The Loss Load Factor can be applied to historical load data, where the maximum load (and hence load loss during maximum load) is known (the maximum load loss is typically calculated via load-flow). For planning studies the maximum load may take into consideration the effects of events such as extreme weather and cold load pickup. The Loss Load Factor is only valid if the condition for the peak load (upon which the Loss Load Factor is based) coincides with the assumptions used in the peak load prediction by the planner/designer. The expected load loss will be significantly overstated if the planner/designer uses typical values for Loss Load Factor but includes a safety factor in the peak load prediction without adjusting the Loss Load Factor accordingly. As the load losses increase with the square of the load current, a 10% peak load safety factor will overstate the maximum load loss by approximately 21% (the average load loss will also be overstated by 21% if the Loss Load Factor is not adjusted accordingly). It is primarily for this reason that load loss calculations and maximum thermal loading and voltage drop calculations are often separated in network planning and design studies. The assessment of losses should be an integral part of planning and design. For the purposes of this research it is desirable to be able to cater for the requirements of loss analysis, thermal loading and voltage drop assessment (for different levels of risk) using the same network and load data.
- The average load loss is estimated but the time-of-use characteristic of the load loss is not described. As discussed further in section 5.3, the cost of losses is dependent on the co-occurrence of the loss with generation and network load peaks. For the purposes of this research, techniques that calculate load losses during different time periods (time of day, day of week and season of year) will enhance loss assessment for planning and design.

The loss calculation method developed by this research will need to be compared with the Loss Load Factor method as used by Nickel and Braunstein [1981], Cespedes et al [1983], Flinn et al [1983], Baylor and Gustafson [1989], Grainger and Kendrew [1989], Bacelar [1995], NRS 034-1 [1999], Sellick [1999], Davidson et al [2002] and Falaghi et al [2005].

### 5.2.3 Network simplification

The availability of network and load data influences the selection of an appropriate load loss calculation method.

Change [1968] simplifies data requirements by deriving loss approximations for feeders supplying evenly distributed load.

Schultz [1978] provides loss estimation formulae for MV networks based on feeder area, voltage level, load density and MV primary and MV lateral conductor sizes. The method is developed for generalised analysis. Schultz [1978] cautions that the results are not always directly applicable to specific networks.

The requirement for the simplifications used by Change [1968] and Schultz [1978] were also linked to the computing power available at that time. The methods developed by Change [1968] and Schultz [1978] do not account for the individual branch loading characteristics. The effects of diversity and unbalance are not accurately modelled. For the purposes of this research it is assumed that a per-branch network model is available, and network simplifications are not required.

### 5.2.4 Network state-estimation

In transmission and sub-transmission HV network loss calculations, increased network and load visibility can lead to the use of state estimation for loss calculation [Cespedes et al, 1983]. Loss calculation via state estimation is only applicable to the calculation of losses in existing networks. Due to the lack of visibility in distribution networks and the requirement for planning and design loss estimation in future networks and years, state estimation is not considered further.

### 5.2.5 Shunt capacitor banks

The research by Kyaruzi [1994] indicates that utility shunt capacitors can have a large impact on network losses, and as such should be included in this research. There are two basic options to include the effect of utility shunt capacitors on losses:

- 1) Indirect consideration via adjustment of load characteristic: The load magnitude and power factor (of loads) are modified to include the effect of shunt capacitors.

- 2) **Explicit modelling of shunt capacitors:** The effect of the reactive power compensation on branch currents is modelled directly in the loss calculation (consumer loads are unchanged).

For the purposes of this research, option 2 is preferred as the impact of shunt capacitors on individual branch (conductor) currents/losses can be assessed.

#### 5.2.6 Multiple load-flow analysis

Improvements in modern computing power enhance the feasibility of multiple time interval load-flow simulations such that the losses in different time interval can be calculated taking into consideration the dynamic nature of both the load and network (e.g. capacitor bank switching, transformer tap adjustment and load voltage dependency) [Carter-Brown, 1999]. In distribution networks the majority of loads are modelled as constant current [Bacelar, 1995] and South African distribution transformers are operated in fixed tap [Carter-Brown and Gaunt, 2006b]. The improved accuracy via multiple time interval load-flow may not be justified and needs to be tested.

#### 5.2.7 Load loss and voltage drop

In LV networks the network impedance is predominately resistive [Herman, 1993b]. Low income domestic network design calculations can be simplified by assuming a unity load power factor [Herman, 1993a; Herman, 1993b]. The LV network loss during peak can be approximated from the maximum total load and LV voltage drop [Bacelar, 1995; Gaunt, Unk]. This method can provide a useful indication of losses, especially in networks where network data is not readily available (for per branch load-flow analysis) but voltage and load measurements can be performed. Even if the loss at a particular instance in time is correlated to the voltage drop at that time, techniques are still required to calculate the loss at other times. For planning and design studies, estimating network losses based on total voltage drop introduces additional errors (as compared to a per branch analysis) as the load characteristic supplied by each branch is not considered. The estimation of network losses based on total voltage drop has not been considered further.

### 5.2.8 Loss calculation in unbalanced networks

Current and voltage unbalance arises due to [Chen, 1995]:

- Asymmetry in the configuration of power system components in three phase networks, such as un-transposed lines and open delta transformers.
- Unbalanced loads, which include single phase loads, and loads taking three phase supplies where the phase currents are not the same.

The asymmetry referred to by Chen [1995] can be extended to include unbalanced distribution technologies such as single phase, phase-to-phase, bi-phase and SWER.

In three phase distribution networks the predominant cause of current and voltage unbalance is unbalanced single phase loads [Chen, 1995].

Bacelar [1995] makes allowance for the effect of load unbalance by increasing the load loss by an unbalance factor which is based on the assumption that on average, the greater phase current is 20% higher than the average phase current. The unbalance factors vary between 1.1 and 1.162.

Tobin and Glynn [1991] increase the calculated losses by 10% and 15% for MV and LV networks respectively. The increase is attributed to account for the effects of load unbalance and the averaging in load data collection.

Cespedes et al [1983] ignore the effect of load unbalance, stating that this simplification does not introduce significant errors for the power system analysed (the Columbian distribution network). The validity of this assumption is questionable in light of the unbalance factors used by Bacelar [1995] and Tobin and Glynn [1991].

The unbalance factors used by Bacelar [1995] and Tobin and Glynn [1991] are not based on stochastic load models, and could vary significantly between different networks. The use of general unbalance factors will result in errors when applied to individual networks. In South Africa extensive use is made of single phase MV and LV technologies (section 2.1). Unbalance must be modelled for South African distribution network loss estimation. The stochastic nature of the load, and unbalance, must be considered.

### 5.2.9 Effect of losses on demand and energy consumption

The effect of losses on upstream network/generation loading is influenced by two characteristics:

- **Loss coincidence:** A peak responsibility factor is often used to describe the coincidence between the load loss and network/generation load peak [Nickel and Braunstein, 1981; Bacelar, 1995]. Grainger and Kendrew [1989] use loss coincidence factors to account for the effect of diversity when calculating the demand loss at different network levels. Peak responsibility factor and loss coincidence factor methods are constrained by the lack of suitable data describing these parameters for different customer mixes and numbers. Parameters need to be based on load research [Tobin and Glynn, 1991]. A method whereby these effects are included via the appropriate treatment of load data is desirable.
- **Load voltage dependency:** It is commonly assumed that load losses increase maximum demand and energy consumption as seen by the upstream network/generation [IEC 287-3-2, 1995; Sellick, 1999; Davidson et al, 2002]. Grainger and Kendrew [1989] treat the downstream loads as constant power loads, and use a loss adjustment factor to account for the increase in upstream loading due to downstream network losses. The relationship between upstream loading and downstream losses is dependent on the load voltage dependency, and is discussed further in sections 5.3.2. The requirement to consider the effect of load voltage dependency on upstream network/generation loading in the assessment of losses needs to be tested.

### 5.2.10 Statistical methods for loss estimation

The errors and limitations of the Loss Load Factor approach arise due to the stochastic nature of distribution network loads. Herman and Heunis [2002] recognized that "*To calculate the resistive losses in a LV feeder over a period of time, the loads are best approached as stochastic current signals*". This statement focuses on LV network analysis, where the stochastic nature of the load has the largest impact on expected losses. At higher network levels, such as MV, the increased diversity between individual loads reduces the errors associated with modelling loads without consideration for their stochastic nature. Techniques providing acceptably accurate results for LV loss analysis may also be adequate for MV loss analysis requirements, but simpler techniques might be appropriate for MV network analysis.

The following characteristics apply to the Herman and Heunis [2002] method for the estimation of the resistive losses on LV residential feeders:

- The average current of a population of customers over time is a probability distribution function which can be represented as a mean and standard deviation. Yamaguchi et al [2005] refer to this load variability as consisting of “predictable” and “unpredictable” components.
- Common electricity usage habits (due to external factors such as time of day and season) in a community cause the loads of different houses to be correlated, arising in the well-known average load profile for residential customers (the “predictable” component referred to by Yamaguchi et al [2005]).
- The property of random variables is used to describe the loss in terms of the load current mean and variance.

$$\text{Loss} = R \cdot E[I^2] = R \cdot (\mu^2 + \sigma^2) \quad 5.2.10.1$$

Loss	Load loss [W]
R	Resistance [ $\Omega$ ]
$E[I^2]$	Expected value of the second moment of the current [amps <sup>2</sup> ]
$\mu$	Average value of the current [amps]
$\sigma$	Standard deviation of the current [amps]

If N consumers are connected to a branch,  $E[I^2]$  can be calculated as [Herman and Heunis, 2002]:

$$E[I^2] = \left[ \sum_{k=1}^N \mu_k \right]^2 + \sum_{k=1}^N \sigma_k^2 + \sum_{i=1}^N \sum_{j=1, i \neq j}^N \rho_{ij} \cdot \sigma_i \cdot \sigma_j \quad 5.2.10.2$$

N	Number of consumers
$\mu_k$	Average value of the load current of consumer k [amps]
$\sigma_k$	Standard deviation of the load current of consumer k [amps]
$\rho_{ij}$	Correlation between the load currents of consumers i and j

- Statistical parameters (mean, standard deviation, variance and correlation coefficient) are extracted from load research data (current recordings of each domestic customer in a sample community) to describe a population of domestic customers.

- The calculation of the variance considers the correlation of load currents. All consumers are assumed to have the same power factor (in this case unity).
- The load losses are calculated for each phase and neutral conductor for each branch based on the network topology (line resistances) and customer connections. Unbalance is explicitly modelled.
- The average load loss is calculated. The load loss over an evaluation period is obtained by multiplication of the average load loss with the duration of the evaluation period.
- Herman and Heunis [2002] test the method against Monte Carlo simulation using load data for the Tambo community (low income residential customers in South Africa) on a representative 12 branch LV feeder. The error of 0.5% (between the expected resistive load loss and Monte Carlo result) verifies that the technique is accurate for a typical low income South African domestic community.

An inspection of the method developed by Herman and Heunis [2002] shows that it has the following possibilities for possible application in this research:

- The equations are developed for a 3 phase 4-wire network. With modification the approach is also applicable to other technologies including bi-phase and 3 phase 3 wire. In 3 phase 3-wire (delta) networks the correlation of phase currents needs to account for the connection of loads between phase and phase (the phase current is displaced by 30° from the phase to phase voltage).
- Mixed residential load classes are not explicitly modelled, but could be included, assuming zero correlation between load classes. The accuracy of this assumption would need to be tested.
- Only the average load loss is calculated. The distribution of the load losses over time (time of day, day of week, month or season) is not known. Derivation of load parameters for different time intervals will provide time specific losses.
- The method should also be applicable to other (non-domestic) loads. When mixing load types the consideration of the load power factor may improve accuracy. The possible errors if load power factor is ignored would need to be assessed.
- The method was developed specifically for, and tested on, LV feeders supplying domestic consumers. It should also be applicable to MV networks operated in radial configurations.
- The forecasting, costing and financial analysis of load losses is not addressed, but the method could form the basis for a greater model incorporating these aspects.

### 5.2.11 Load profiles

Load losses vary with the magnitude of the load. Load profiles, describing the load during different time periods, can be used to enhance load loss estimation and costing.

Bilbao et al [2001] observes that the load profile of a customer can be estimated based on historical consumption data, or standard models can be used for different customer types. If historical consumption data is not available, some customer data is required so that the appropriate customer type can be assigned. Load research data is essential so that suitably adequate load models can be derived. Flinn et al [1983] state that *"a key link [for loss estimation using load profiles] is load surveys which provide 24-hour load profiles for each class of customer throughout the year."*

Chen et al [1994] use a single daily load profile to describe the load variation for loss analysis. The uncertainty in the load profile is not catered for. Grainger and Kendrew [1989] and Flinn et al [1983] use statistical clustering to generate normalised daily load profiles for "significant" days. When applied to HV/MV transformer loading Grainger and Kendrew [1989] observe that *"a year can be represented statistically by between four and six typical days."* The techniques used by Flinn et al [1983] and Chen et al [1994] do not include the uncertainty of the daily load cycle(s). The errors in these methods needs to be assessed when applied to stochastic loads such as domestic consumers.

Oliveira et al [2001] use normalised daily profiles as the basis for load loss estimation:

- Consumers are represented by typical per-unitised daily mean and standard deviation load curves. The profiles are based on an extensive load research project described by Jardini et al [1995].
- LV residential customers (4 categories) are classified based on average energy consumption. LV commercial (47 categories) and industrial (26 categories) customers are classified according to their respective activity. 6 MV customer categories are differentiated.
- The per-unit load profiles are scaled with estimated energy consumption or customer billing data to derive kW load profiles.
- Load loss calculation for both MV and LV networks is performed via load-flow simulation using the mean kW load in each time interval.

- Per-unitised daily load profiles include standard deviation. Load loss calculations are only based on the mean load. The standard deviation is ignored in load loss calculations (same as per Flinn et al [1983], Grainger and Kendrew [1989] and Chen et al [1994]).
- Load currents are assumed to be balanced across the available phases.
- Correlation between customers in the same customer category is ignored.

A method utilising a statistical treatment of the loads (as per Herman and Heunis [2002]) for each time interval using representative daily load profiles (of mean and standard deviation) should be investigated further and compared with the results of the methods used by Chen et al [1994] and Oliveira et al [2001].

#### 5.2.12 Uncertainty in expected loss results

Loss analysis requires the specification of parameters for which there may be considerable uncertainty including conductor size, line length, number of customers, customer load characteristic and connection phasing [Heunis and Herman, 1999b].

By assigning probability distribution functions to the factors influencing the expected loss, the expected loss can be expressed as a probability distribution function [Herman and Heunis, 2002]. The calculation of the expected loss probability distribution function however becomes complex and requires significantly more load information [Herman and Heunis, 2002]. This is demonstrated in the method developed by Fourie [2001] which uses a beta distributed load model for loss estimation.

A simpler method is to assign a set (low, middle and high) of values to each parameter to account for uncertainties and the lack of suitable data [Nazarko et al, 2000; Hong and Chao, 2002; Herman and Heunis, 2002]. The loss result is then a fuzzy set (low, middle and high) showing a range of expected values.

For operational purposes a range of expected loss values is useful. For planning and design only the expected average value of loss is required. Unlike thermal loading constraints and voltage drop requirements, the planner/designer does not need to assess the risk of loss exceedance. In distribution networks numerous similar networks are planned/ designed. The plan/design must be based on expected average loss, with the understanding that the losses in individual networks will vary from the average. This is supported by the results of Camargo et al [2001] who compared deterministic and probabilistic approaches to cable sizing. By providing a range of values for the input parameters, the probabilistic method provides

information on the risk associated with each option (cable size). However the optimal (least cost) cable size is the same as for the deterministic calculation.

For the purposes of this research it is not necessary to express the expected losses as a probability density function or fuzzy set.

### 5.2.13 Calculation of load losses in future years

A prerequisite to the lifetime costing of losses is the calculation of load losses in each future year in the evaluation period. The generally accepted approach [IEC 287-3-2, 1995; Willis, 1997; NRS 034-1, 1999; Sellick, 1999] is the extrapolation of the initial year load loss to each future year using the assumption that the change in load current is proportional to the change in forecasted load magnitude (the change in load loss is hence proportional to the change in load magnitude squared), and uses the following parameters:

- Initial year load loss: The load loss in the initial year.
- Evaluation period: Typically the equipment anticipated lifetime.
- Load growth: Usually expressed in % growth per annum (compound growth) but could be any shape and is not necessarily exponential.

## 5.3 COSTING OF TECHNICAL LOSSES

The costing of technical losses is important for network planning and design. An optimal balance must be achieved between the cost of supplying losses and the cost of reducing losses. Tobin and Glynn [1991] observe that "*Expenditure on loss reduction is often regarded as optional*" resulting in potential underinvestment thereby committing the utility to increased costs. "*Under-valuing the distribution losses diverts investment towards the generation and transmission system levels, to lesser advantage. This leads to non-optimal system development overall and to reduced economic efficiency and waste of resources.*" [Tobin and Glynn, 1991]. Conversely over-valuing the cost of losses diverts investment to the distribution network.

### 5.3.1 Traditional approaches to the costing of losses

Four financial analysis methods are in general use for the costing of technical load and no-load losses [Nickel and Braunstein, 1981]:

- Present worth of annual revenue requirement.
- Levelised annual cost.
- Annual cost.
- Equivalent investment cost.

The method adopted for a particular analysis depends on the scope of the analysis, including the requirement to model the effects of inflation and equipment upgrading or replacement (once an economic loading limit is exceeded).

In a vertically integrated Electricity Supply Industry loss costing methods such as described by Nickel and Braunstein [1981] and Tobin and Glynn [1991] are based on generation capital and running costs.

In an Electricity Supply Industry that is not vertically integrated losses that result in increased total load are paid for by the distribution utility at the same rate as for customer loads. The tariff signals may differ significantly from those used in traditional loss evaluation methods based on generation capital and running costs [Davidson et al, 2002]. This vertically separated approach could lead to sub-optimisation as the real cost of losses to the Electricity Supply Industry may be significantly different from the costs based on the tariffs paid by the distribution utility [Davidson et al, 2002].

In a vertically separated Electricity Supply Industry Davidson et al [2002] recommend "*The best method for costing losses is to use the long-run marginal cost of the supply to each level of the power system. This cost should reflect cost of production, in terms of generating capacity, fuel consumption and the cost of capacity in the transmission and distribution networks.*"

Tobin and Glynn [1991] caution against the costing of losses based on short-run costs that only consider generation costs at that point in time. This approach leads to under and over estimation of loss costs during periods of excess and insufficient generation capacity respectively [Tobin and Glynn, 1991].

Tobin and Glynn [1991] consider the cost of losses in the distribution networks of the Electricity Supply Board of Ireland:

- *"Long-run [generation and transmission] costs should be used since losses are a long-term issue" [Tobin and Glynn, 1991] and the use of long-run costs are necessary "to provide a consistent policy on losses" [Tobin and Glynn, 1991].*
- From the perspective of transmission and generation, distribution losses are indistinguishable from load, and *"There is no basis for differentiating between load and losses within the distribution system."* [Tobin and Glynn, 1991].
- *"Since most of the cost of losses is related to the generation system, loss investment analysis should be done on the same basis as generation investment" [Tobin and Glynn, 1991].*
- Loss evaluation should be performed over the long term (25 years) using the same discount rates as for major projects. Future developments will be based on incremental costs and benefits at that time. Even though future development may modify the networks, they do not alter the underlying economics. The benefits of the investment will be maintained over the life span of the equipment (unless there is load reduction).

The majority of evaluations separate the energy and demand cost components of losses into a two-part loss evaluation tariff [Nickel and Braunstein, 1981; Tobin and Glynn, 1991; IEC 287-3-2, 1995, Willis, 1997; Sellick, 1999]:

- **Energy loss cost:** Refers to the generation running cost (Rand/kWh), which is primarily determined by the fuel cost. The energy cost is dependent on the real power consumption.
- **Demand loss cost:** Refers to the annualised capital cost (Rand/kVA) pertaining to simply having generation and network installed and available to supply losses (seen as load by the upstream network and generation). The demand cost is dependent on both the real and reactive power loss.

Energy loss costs are traditionally split into base and peak-generation components (used with no-load and load loss costs respectively) [Nickel and Braunstein, 1981; Tobin and Glynn, 1991] and do not consider the load shape. It is assumed that the majority of the load loss occurs during the generation peak (load losses vary with the square of the load current). Errors may be large when applied to networks where the period of peak load does not coincide with the generation period of peak load.

In traditional methods using maximum demand and base and peak-generation energy costs, generation/transmission demand and energy costs are the signals to manage the maximum and average values of distribution losses respectively. The time-of-use dependent cost of generation is not taken into consideration. High load losses may have little economic impact if they occur during periods of surplus generation capacity. Different load classes may have significantly different load shapes and the cost of load losses could vary significantly between load classes.

Nickel and Braunstein [1981] base distribution network reactive loss costs on MV shunt capacitor costs. No load loss and load loss reactive energy costs are based on fixed and switched shunt capacitor costs respectively. In capacitor installations there is no fuel cost, only capital, operational and maintenance costs [Nickel and Braunstein, 1981]. The reactive loss cost is however very small compared to the active power loss cost [Nickel and Braunstein, 1981], and for most applications can be ignored without significantly compromising accuracy. This needs to be confirmed for South African evaluations.

For the purposes of this research, charges for bulk power purchase from generation/transmission are appropriate for the costing of distribution technical losses if these charges:

- are based on long-run marginal costs of generation, and
- account for the cost differences between base and peak-load generation, and should preferably be time-of-use based so that the load shape can be accounted for (no longer a simple two-part energy and demand tariff).

The tariff used by a utility for the costing of technical losses (describing the generation/transmission costs) will henceforth be referred to as a Utility Loss Tariff.

Note that if Utility Loss Tariffs are time-of-use based (not a two-part tariff) the Loss Load Factor approach is inadequate and a time-of-use related model of load losses is required to calculate the cost of losses.

### 5.3.2 Relationship between load losses and reduction in revenue

As identified in section 2.4.4, load energy consumption and demand are influenced by voltage variation and load voltage dependency. The combination of load current and network impedance results in load loss and reduced consumer energy consumption and demand (for

loads that are not constant power). When considering a constant current load, it is apparent that load losses do not increase the energy or demand supplied by the source network (generation and transmission). There will be no change in upstream generation/network cost if load losses are reduced in the downstream network supplying the constant current load. This applies to passive networks without voltage regulators or automatic tap changing transformers.

The tariff paid by a customer to the utility for energy consumption and demand is henceforth referred to as a Customer Tariff.

Consider the impact of increased series resistance between a source and load for three different load voltage dependencies (table 5.3.2.1):

Load voltage dependency	Technical load loss	Source energy consumption and demand (utility cost)	Customer energy consumption and demand (utility revenue)	Net cost/revenue change dependencies
Constant Power	Increases	Increases	Unchanged	<ul style="list-style-type: none"> <li>• Load loss magnitude</li> <li>• Change in bulk energy and demand purchases from generation/transmission</li> <li>• Utility Loss Tariff charges</li> </ul>
Constant Current	Increases	Unchanged	Reduces	<ul style="list-style-type: none"> <li>• Reduction in customer energy consumption and demand</li> <li>• Customer Tariff charges</li> </ul>
Constant Impedance	Increases	Reduces	Reduces	<ul style="list-style-type: none"> <li>• Load loss magnitude</li> <li>• Change in bulk energy and demand purchases from generation/transmission</li> <li>• Utility Loss Tariff charges</li> <li>• Reduction in customer energy consumption and demand</li> <li>• Customer Tariff charges</li> </ul>

Table 5.3.2.1: Impact of increased series resistance between a source (upstream generation/network) and load in a passive network

Referring to table 5.3.2.1, the net cost due to series resistance varies for different load voltage dependencies, Utility Loss Tariffs and Customer Tariffs. Series resistance varies with conductor size. It can be concluded that conductor size may impact both utility bulk energy purchase costs and utility revenue. Load losses do not necessarily increase utility bulk energy purchases. Increased load loss in networks supplying constant impedance loads reduces total system loading. Note that the above only applies to passive networks.

Technical load losses, consumer energy consumption and utility bulk energy purchases appear to be related. Possible relationships need to be investigated further.

Traditional load loss costing methods as used by Nickel and Braunstein [1981], Tobin and Glynn [1991], IEC 287-3-2 [1995], Willis [1997], NRS 034-1 [1999], Sellick [1999], Curcic et al [2001], Davidson et al [2002], Mandal and Pahwa [2002] and Falaghi et al [2005]:

- base loss costs on generation/transmission costs only,
- assume that load losses increase the energy and demand supplied by the upstream network, and
- ignore any impact on changes to utility revenue due to variations in customer energy consumption and demand.

These traditional methods are valid for constant power loads. The significance with other load types needs to be investigated (see chapter 10).

#### 5.4 NETWORK PLANNING AND DESIGN CONSIDERING TECHNICAL LOSS COSTS

The consideration of the lifetime cost of technical losses can significantly impact distribution network planning and design:

- Neal [1977] observes that even if strengthening or upgrading is performed to address capacity related issues (loss reduction is not the key driver, but rather other requirements/constraints such as thermal loading or voltage limits), the cost savings in reduced losses may offset the capital costs, as was the case with the upgrading of the University of Kentucky's 4kV distribution network to 12kV.
- The IEC 287-3-2 [1995] calculates typical lifetime cost savings in the order of 50% when sizing cables including technical loss costs as opposed to only considering thermal limits.
- The optimal cable and overhead line loading levels calculated by Curcic et al [2001] provide sufficient spare thermal capacity such that the security (abnormal network configuration) requirements of the network can be met at no additional cost. This observation was made in the context of thermally limited networks and may not apply to networks constrained by voltage limits.

The impact of loss costs vary between utilities due to differences in the relative costs of capital and generation, and network and load characteristics. The findings and recommendations of international research and standards (such as Neal [1977], IEC 287-3-2 [1995] and Curcic et al [2001]) may not be directly applicable to South Africa.

This research is focused on optimising conductor sizes. The optimisation of conductor size considering lifetime loss costs warrants specific discussion.

The SABS 0198 [1988]: Part 2, Code of practice for the selection, handling and installation of electric power cables of rating not exceeding 33kV specifies the following criteria for cable selection in South African distribution networks; sustained current rating, allowable voltage drop, short-circuit capacity, mechanical and environmental protection and interference with telecommunication cables. The economic sizing of cables incorporating technical losses is not discussed.

The NRS 034-1 [1999] does not provide a method for economic conductor sizing, but refers to the IEC 61059, which has been replaced with the IEC 287-3-2 [1995].

The IEC 287-3-2 [1995] bases the calculation of the optimal conductor size for cables on the Net Present Value of future load losses. The total cost is the sum of the initial capital cost and the cost of load losses during the cable lifetime. Load loss costs are based on energy and demand costs (the Utility Loss Tariff is assumed to be a two-part tariff). The Loss Load Factor is used to calculate the average load loss energy. There are two conceptual alternatives for the calculation of the optimal conductor size for a given branch:

- 1) Calculate a range of economic currents for each possible conductor size, and then select the size whose economic range includes the load being considered.
- 2) Calculate the optimal cross sectional area (theoretical) for the required load, and choose the closest standard conductor size. Due to non-linear cost functions the closest standard conductor may not be the optimal, and the closest (larger and smaller) sizes should be tested and the least cost (lifetime) selected.

The IEC 287-3-2 [1995] method has the following limitations, which (as will be shown) are critical for application in South African domestic electrification networks:

- A non-statistical description of the load is used. The Loss Load Factor forms the basis for energy loss calculations. The limitations of the Loss Load Factor method have been documented in section 5.2.2.
- Neutral conductor losses are not included.
- It is developed for three phase systems, and the effect of load unbalance ignored.
- Load growth is limited to a fixed percentage per year.

- The effect of conductor voltage drop on utility bulk energy purchase costs and revenue (see section 5.3.2) is not considered.

The methods used for conductor sizing by Willis [1997], Sellick [1999], Mandal and Pahwa [2002] and Falaghi et al [2005] are based on the same principles as the IEC 287-3-2 [1995]. In meshed networks changes in conductor size affect the branch impedances and hence influence branch currents. Falaghi et al [2005] use an iterative technique to optimise conductor size in each branch whilst complying with thermal constraints and voltage drop requirements.

Curcic et al [2001] improves on the IEC 287-3-2 [1995] method as follows:

- A relationship between conductor resistance and thermal rating is used to calculate the optimal utilisation (optimal loading level divided by thermal load limit) of a cable type (e.g. 11kV, Copper, Paper Insulated Lead Covered) for a specific load characteristic.
- An annual load profile is used to describe variations in consumer load and perform time-of-use loss costing. The load profile does not account for mixtures of customers, varying customer numbers or load unbalance. The stochastic nature of individual loads is not described by the profile.

The methods used by Willis [1997], Curcic et al [2001], Mandal and Pahwa [2002] and Falaghi et al [2005] contain the same inherent limitations as the IEC 287-3-2 [1995]. The accuracy of the load loss calculation and costing approaches used in these methods need to be tested and compared with the results of the method developed by this research.

The economic loading limit of a conductor and the effect of technical loss cost on recommended thermal loading limits is well described [Mandal and Pahwa, 2002; IEC 287-3-2, 1995; Willis, 1997]. In networks limited by voltage drop, the reduction in economic loading limits (due to loss costs) increases the economic load reach of a conductor set at a particular voltage level [Willis, 1997]. The effect of technical loss costs on voltage drop limits has not been subject to extensive research. In a study on loss minimisation in the rural networks in India, Sen Gupta et al [1984] show that the minimisation of voltage drop and technical losses can have conflicting requirements, specifically on the location of substations.

The method used by Sellick [1999] to combine voltage drop assessment and economic conductor sizing is discussed in section 6.2 and, as will be shown, is not considered adequate for South African domestic electrification conductor size optimisation.

## 5.5 LOOKING FORWARD

The following properties are desirable for a load loss calculation method as would be appropriate for the optimisation of conductor sizes in South African domestic electrification networks:

- Consider the stochastic nature of individual loads.
- Support different unbalanced network technologies (three phase, single phase, bi-phase and SWER) and voltage levels (MV and LV).
- Include neutral conductor losses.
- Account for varying customer numbers and diversity by calculating losses separately for each branch. A per-branch network model is used, and network simplifications are not required.
- Include the effect of load power factor.
- Include the effect of load balancing (at peak loading and other time periods).
- Account for diversity between load loss demand and upstream network/generation peak loading.
- Cater for networks supplying loads with different load shapes i.e. mixtures of non-homogeneous loads, with different load forecasts.
- Use the same network and load data as required for thermal loading and voltage drop assessment.
- Provide a time-of-use description of the load loss (for use with time-of-use Utility Loss Tariffs).
- Explicitly model shunt capacitors, and their impact on the losses in each branch.
- Include changes in the load over the lifetime of the network.
- The method can be limited to radial networks.

A method utilising a statistical treatment of the loads (as per Herman and Heunis [2002]) for each time interval using representative daily load profiles (of load mean and standard deviation) should be investigated further.

The loss calculation method developed by this research will need to be compared with the Loss Load Factor and average load profile load-flow methods and Monte Carlo simulation using load research data.

The loss costing method should have the following characteristics:

- Future costs should be calculated as a Net Present Value based on forecasted financial parameters.
- The Net Discount Rate used should be the same as for major generation projects.
- Loss evaluation should be performed over the long term (e.g. 25 years), but the evaluation period should be adjustable based on the equipment anticipated lifetime.

Charges for bulk power purchase from generation/transmission (Utility Loss Tariff) should have the following characteristics:

- Based on the long-run marginal costs of generation.
- Account for the cost differences between base and peak-load generation, and should preferably be time-of-use based so that the load shape can be accounted for.
- Included reactive energy costs, but this is not a critical requirement and needs to be confirmed.

The impact of conductor load losses on utility bulk energy purchases appears to be dependent on the load voltage dependency. Technical load losses, changes in utility bulk energy purchases and changes in consumer energy consumption appear to be related. Changes in consumer energy consumption (due to conductor voltage drop and load voltage dependency) may need to be considered when evaluating conductor load losses. This needs to be investigated further.

## **6. COMBINING TECHNICAL LOSS AND VOLTAGE DROP ASSESSMENT IN CONDUCTOR SIZE OPTIMISATION**

Chapters 4 and 5 considered voltage drop and technical loss assessment separately. In order to establish optimal conductor sizes and associated voltage drops, voltage drop and technical loss assessment need to be combined into a common model such that the voltage drop characteristics of an optimum network design can be assessed.

Most techniques to calculate optimal conductor sizes and associated voltage drops are deterministic. This chapter starts with a review of the deterministic techniques and their failings for the purposes of this research, leading to the work by Sellick [1999]. Due to its similarity to this research, a detailed analysis of Sellick's work is provided.

### **6.1 DETERMINISTIC METHODS**

Willis [1997] transforms the economic loading range of a conductor (the loading that results in minimised capital and lifetime load loss cost as compared to the other conductors in a set) into an economic load reach. The result is the maximum distance that power can be moved (for a particular conductor/voltage and load characteristic) at a particular voltage drop limit before additional costs are incurred to meet voltage limits. The corollary to this analysis is that the optimum maximum voltage drop limit can be calculated for a given load reach requirement i.e. the voltage drop limit for which there is no additional cost penalty at a particular voltage. Two concepts are important; conductor economic loading limits affect the optimum conductor size and hence voltage drop, and the optimum voltage drop is dependent on the physical layout of the network including the distance that power needs to be moved.

Lakervi [1984a] develops linear cost functions for voltage drops and losses. The feeder layout has a significant impact on the optimal lifetime cost. An optimal solution is only achieved if the feeder layout and conductor sizes are optimised. The linear cost functions are

developed further by Lakervi [1984b] to calculate relationships between lifetime costs and voltage drops using Lagrange multipliers.

Falaghi et al [2005] constrain economic conductor size selection using an iterative solution with a maximum voltage drop limit constraint. The lifetime costs associated with conductor voltage drop are not assessed.

The methods relating capital and technical load loss lifetime costs and voltage drop by Willis [1997], Lakervi [1984a], Lakervi [1984b] and Falaghi et al [2005] have the following limitations, which render them unsuitable for the purposes of this research:

- Voltage drop and loss calculations are deterministic, and do not cater for uncertainty and risk.
- Deterministic load models do not account for the stochastic nature of loads, including the effects of load unbalance and diversity. Errors in deterministic load models have been shown to be high [Sellick and Gaunt, 1995].
- The impact of load losses on utility bulk energy purchases, as influenced by load voltage dependency, is not included (a constant power model is assumed).
- The effect of conductor voltage drop on consumer energy consumption (utility revenue) is not accounted for (a constant power model is assumed).
- Loss costs are based on simplistic models for energy and demand only, and do not account for time-of-use loss costs.

## 6.2 SELICK METHOD: HERMAN BETA WITH LOSS LOAD FACTOR

In preceding chapters some mention has been made of Sellick [1999]. Sellick's work has been one of the more useful references, and due to its similarity to this research, it merits a detailed analysis.

Sellick [1999] develops a method for the calculation of the voltage drop at which the overall lifetime cost of a low voltage domestic distribution feeder is minimised. The lifetime cost consists of the initial capital cost, and the lifetime cost of technical load losses. Common costs not associated with the conductor size (non-technical losses, metering, kiosks) are excluded from the evaluation.

The method is very similar to the IEC 287-3-2 [1995] in that the optimal conductor area is selected based on:

- A linear cost approximation of conductor capital cost (for a particular voltage level, technology and conductor family e.g. 1kV three phase four wire aerial bundle conductor).
- Future costs are discounted to the Net Present Value using inflation and discount rates, which are fixed for the evaluation period. Sensitivity analysis shows that the model is not extremely sensitive to changes in the financial parameters.
- The Loss Load Factor is used to calculate the average load loss based on the load loss at peak loading.
- The optimal conductor area, which results in minimum lifetime cost, is calculated for each branch.
- The lifetime costs of the closest higher and lower standard sizes are calculated. The least lifetime cost conductor is chosen as the optimal standard conductor.

The method improves on the IEC 287-3-2 [1995] approach as follows:

- The voltage drop calculation is based on the Herman Beta method which, for voltage drop estimation at peak load, accounts for the stochastic nature of domestic loads.
- The load ADMD and Loss Load Factor are based on recorded load data representative of South African domestic consumers.
- The Loss Load Factor varies for each branch, and is dependent on the number of customers supplied by the branch.
- The voltage drop is calculated based on the optimal conductor selection.
- The annual load growth is not fixed (the load is forecasted for each year so that a typical S-curve load growth can be modelled).

The optimum conductor size is selected that will minimise the lifetime cost. The resulting voltage drop is calculated in each branch using the Herman Beta method for a given confidence level (typically 90%). The resultant optimum voltage drop is a consequence of the conductor selection.

The method uses factors to describe the voltage drop variation over the conductor lifetime (load forecast), and annual load loss maximum demand correlation with monthly load loss maximum demands (load loss demand costs are paid monthly).

The limitations of the method include:

- It is only applicable to LV domestic network analysis.
- It uses a three phase network model, with some adjustment for unbalanced loading. The accuracy of the adjustments is uncertain.
- It is based on a two-part demand and energy charge, and does not directly cater for time-of-use load loss costs.
- The impact of load losses on utility bulk energy purchases, as influenced by load voltage dependency, is not included (a constant power model is assumed).
- The effect of conductor voltage drop on consumer energy consumption (utility revenue) is not accounted for (a constant power model is assumed).
- The method assumes that the expected loss at peak load can be approximated by the Herman Beta current with a 50% confidence level. The accuracy of this assumption is not tested by Sellick [1999]. Referring to annex A, the error in Sellick's method in branches supplying less than 10 customers falls between -5.82% and -93.6% for the three communities tested. The use of the Herman Beta current at peak loading is not suitable for load loss estimation purposes in network supplying less than 50 consumers.
- The Loss Load Factor is fixed for the evaluation period. Energy and demand are assumed to increase at the same forecasted rate. Future changes in load shape are not accounted for.
- The sample feeders are restricted to three phase technology with even customer distribution and ideal load balancing. They are not representative of South African domestic electrification networks.

For the networks tested by Sellick [1999], the optimum LV voltage drop at peak (with a 90% confidence) varies between 8.2% and 20.5%. Compared to designs based on thermal limits and a maximum voltage drop of 10%, the typical reduction in lifetime cost is between 9% and 11%.

In light of the limitations described above, the conductor size optimisation and associated optimum voltage drop limits calculated by Sellick [1999] are questionable. The method is a foundation for further work.

### **6.3 CONCLUSIONS**

None of the methods or approaches identified in this research for conductor size optimisation adequately allow for:

- lifetime capital costs, technical loss costs and voltage drop costs due to changes in consumer energy consumption and demand,
- the stochastic variation of individual loads,
- combined MV and LV networks, and
- a range of network technologies.

A conductor size optimisation method addressing these shortfalls appears useful.

### **6.4 LOOKING FORWARD**

A method for the assessment of optimal conductor sizes and associated voltage drops for application in South African electrification network planning and design should have the following characteristics:

- Voltage drop calculations should be probabilistic such that risk can be quantified.
- The stochastic nature of the load should be adequately described in loss and voltage drop calculations.
- Lifetime costs should include costs associated with load losses and conductor voltage drop (the effect of conductor size on utility bulk energy purchases and utility revenue).
- Different network layouts, technologies and nominal voltage levels should be catered for.

## **7. OVERVIEW OF THE PROPOSED METHOD FOR OPTIMAL CONDUCTOR SIZING AND VOLTAGE DROP CALCULATION**

Previous chapters documented practices for network and load modelling with specific emphasis on technical loss and voltage drop calculations. The desirable characteristics and promising methods have been identified for this research.

This chapter starts with a summary of the requirements for the optimisation of conductor size to minimise lifetime capital, technical loss and voltage drop costs, and the calculation of the associated voltage drops. The proposed method is introduced, with each of its major components, which are then documented in additional detail.

### **7.1 SUMMARY OF REQUIREMENTS**

A method is required for the optimisation of conductor size to minimise lifetime costs associated with conductor installation (capital), technical losses and change in utility revenue due to conductor voltage drop. The voltage drop associated with the optimal conductor size needs to be calculated. The method should have the following characteristics:

- The network model should be unbalanced, support different technologies (delta, star, phase-to-phase, SWER, single phase and bi-phase), voltage levels (MV and LV), OLTC and DETS transformers, shunt capacitor banks and voltage regulators.
- Technical load loss and voltage drop calculations should accurately account for the stochastic nature of the load.
- LV voltage drop calculations should be probabilistic and associated with a user defined percentile and confidence level. Deterministic techniques may be sufficient for MV network analysis.
- Mixed load classes should be supported e.g. a school, shop, clinic and domestic loads all on the same LV feeder.

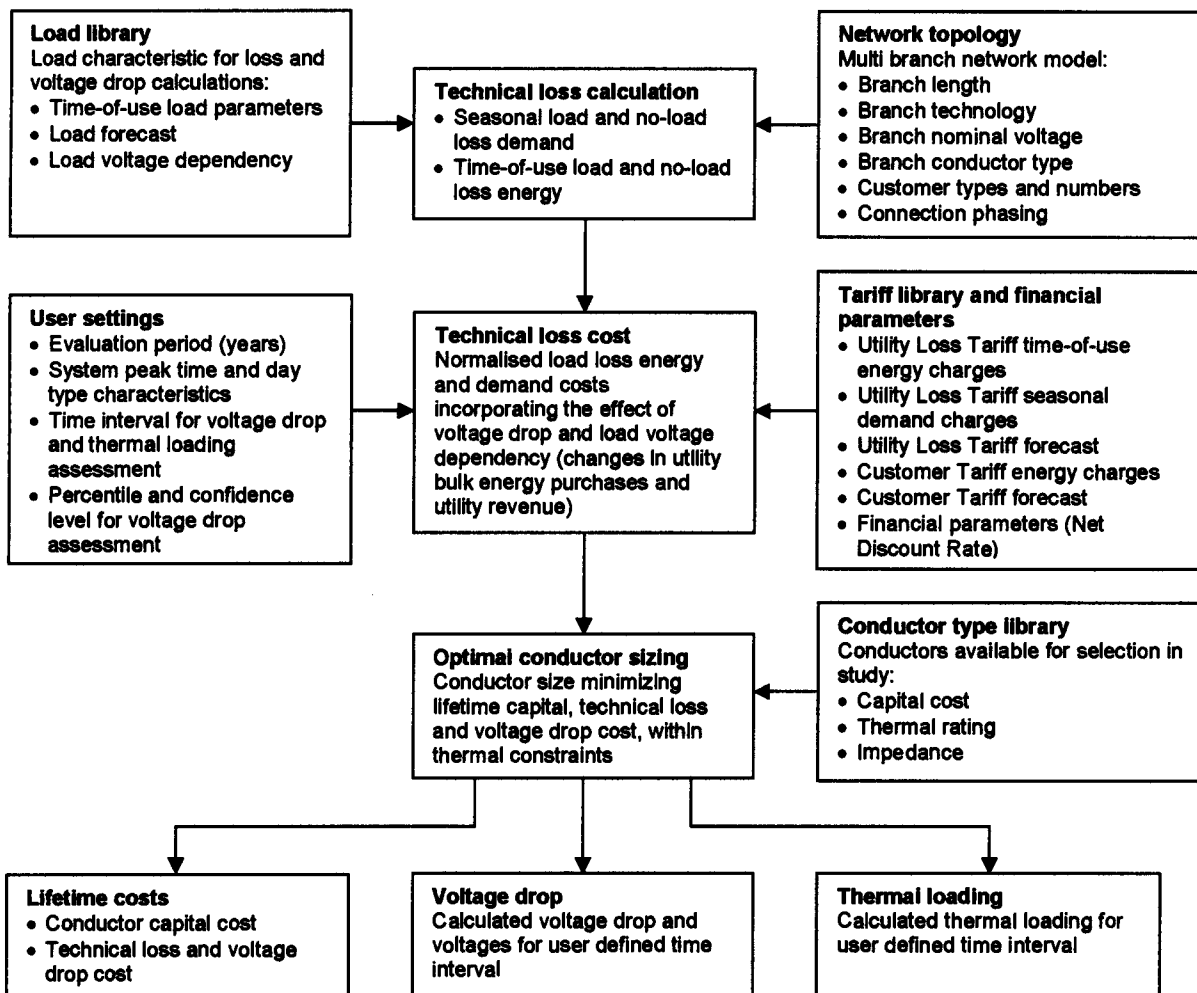
- Charges for the costing of losses should be time-of-use based.
- Lifetime costs should include costs associated with load losses and conductor voltage drop (the effect of conductor size on utility bulk energy purchases and utility revenue).
- MV and LV networks should be catered for in the same study so that the relationships between these network levels can be analysed.
- Future year network reinforcement should be supported.
- Loss, thermal and voltage drop calculations should be integrated so that a single tool and set of data can be used for all three of these planning and design analysis requirements.
- Lifetime load and no-load losses should be calculated.
- Conductor size should be optimised to minimise capital and lifetime technical loss and voltage drop costs (changes in utility bulk energy purchases and utility revenue as affected by conductor size).
- Thermal loading and voltage drop should be calculated at a user defined period, including a future year.
- Load models and the application thereof must be based on South African load research data.
- The method should be suitable for practical network planning and design.

## 7.2 OVERVIEW OF THE PROPOSED METHOD

The proposed method is illustrated in figure 7.2.1, and meets the requirements summarised in section 7.1. The main attributes are as follows, and are discussed in more detail in subsequent sections:

- Network topology: The network is defined by the user. Each network branch is explicitly modelled. The user specifies the voltage levels, technologies, branch lengths, and the numbers and locations of each type of customer/load. The load characteristics are specified in a load library. If more than one conductor size is specified for a branch, it is optimised (see point below). MV and LV networks can be analysed simultaneously, but are limited to radial configurations.
- Load model (load profile uncertainty): Fixed Loads and variable loads are supported. Fixed Loads have unity Load Factor and are constant for the evaluation period. Variable loads are associated with different Load Groups (a consumer load class will henceforth be referred to as a Load Group). Load Groups are described by daily load profiles using a user defined time interval. Within each time interval the load power factor, apparent power mean and variance of the apparent power mean are specified. The correlation of load currents within time intervals is specified.

Figure 7.2.1: Method for optimal conductor sizing and voltage drop calculation



- **Technical loss calculation:** The expected technical load loss (energy and demand) is calculated in each phase of each branch. The expected technical no-load loss (energy and demand) is calculated for each transformer.
- **Technical loss and voltage variation costing:** The Net Present Value cost of technical losses is calculated using the time-of-use Utility Loss Tariff. The effect of voltage drop on energy consumption, and hence utility revenue, is factored into the analysis using Customer Tariffs and load voltage dependency.
- **Conductor size optimisation:** Where more than one conductor size is specified in a branch, the optimal size is selected from the user defined list of conductors. The optimal conductor size minimises the lifetime capital, technical load loss and voltage drop costs.
- **Voltage drop assessment:** The LV voltage drop is calculated using the probabilistic QOS voltage drop assessment method. Deterministic MV load-flow is used for MV network voltage drop calculation. The minimum voltage at network nodes can be calculated for a

user defined hour of day, day type, season of year, year (present or future), and percentile and confidence level.

- **Thermal loading assessment:** Maximum conductor thermal loadings are calculated and used to constrain optimal conductor sizing.

### 7.3 NETWORK TOPOLOGY

The network model is limited to radial network configurations. The following network components are modelled:

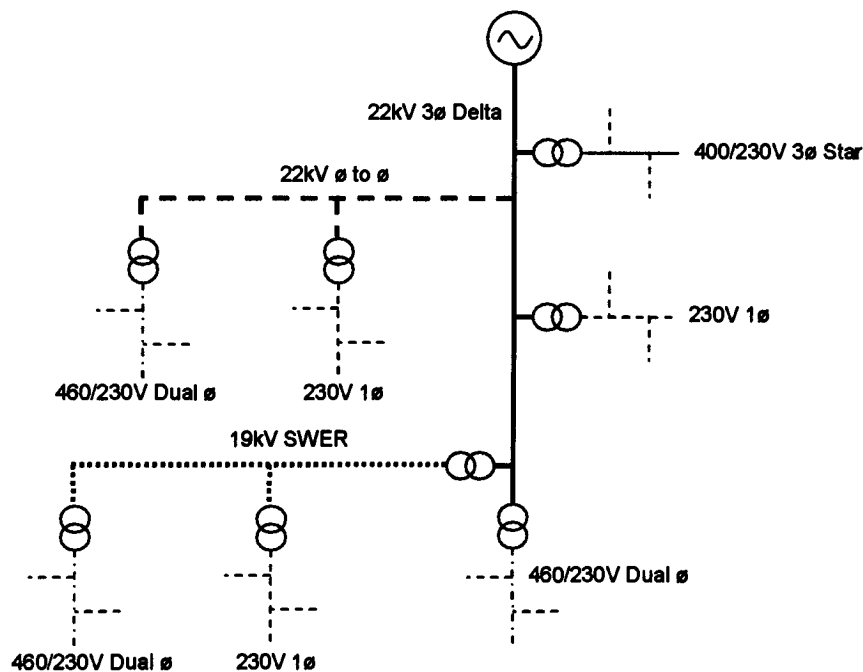
- **Conductors:** Lines are assumed to be transposed i.e. phase impedances are identical. The neutral impedance can be specified independently to the phase impedance.
- **Transformers:** Phase impedances are identical. Core losses are fixed and do not vary with the magnitude of the primary voltage.
- **Shunt capacitor banks:** Perfectly symmetrical. Dielectric losses are not included.
- **Loads:** The number (and phase connection) of consumers of each Load Group (variable load) is specified at network nodes. The size, power factor and phase connection of each Fixed Load is specified at network nodes.

The load loss and voltage drop calculations are unbalanced calculations and consider the characteristics of each phase/neutral conductor in each branch. The resistance is assumed to be constant and is not adjusted for temperature variations.

The network connectivity and layout is specified by the user. For each network branch the line length, nominal voltage, technology, and conductor size are specified. If more than one conductor size is specified then the size is optimised from the selected list (see section 7.7). The phase connection of lines and loads are user specified.

Technologies are limited to delta, star, phase-to-phase, single phase, bi-phase and SWER as are commonly used in South Africa. The voltage levels are user specified, and MV and LV networks can be combined in the same network study (see figure 7.3.1).

Figure 7.3.1: Example of mixed MV and LV networks and technologies in the same study



#### 7.4 LOAD MODEL

Jardini et al [1995] show that if suitable load research data is available and characteristic load curves are derived, the mean and standard deviation of a group of customers can be estimated in each time interval, with good results.

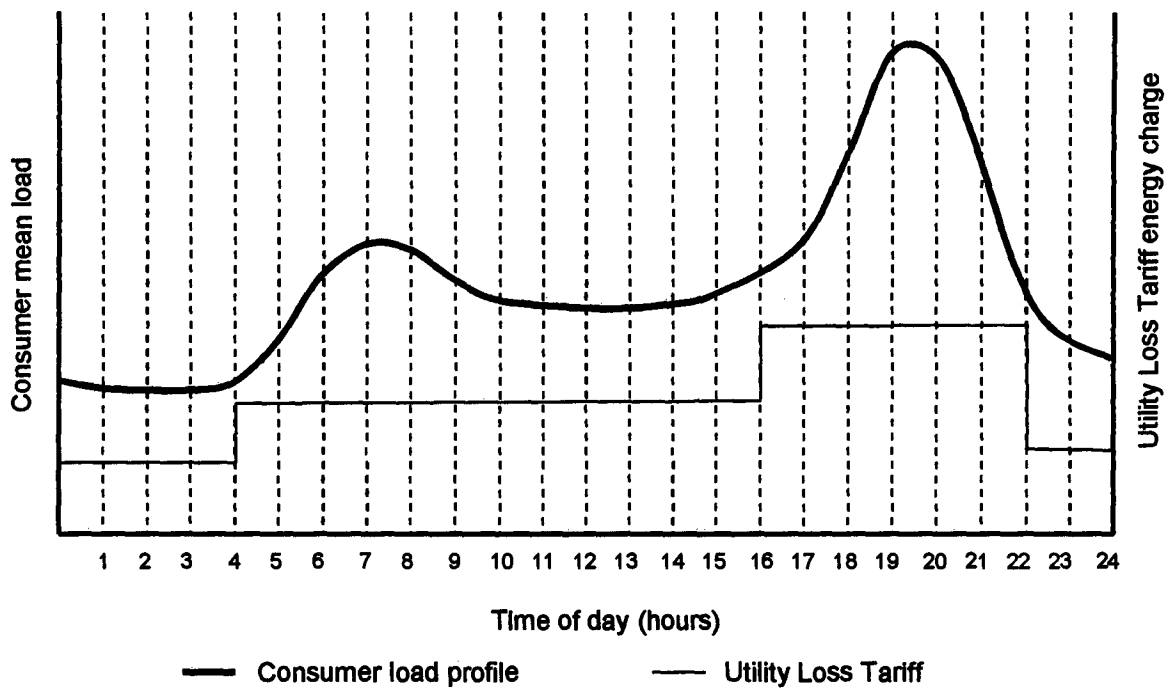
The load models used in this research are based on load profile uncertainty (a time-of-use load model describing both the mean and variance of the load). The following need to be defined for a load profile model:

- The time interval e.g. 5 minutes, 30 minutes, 1 hour etc.
- The significant day types including the possible differentiation between days of the week, weekdays, Saturdays and Sundays.
- Seasonal variations e.g. summer, winter, months of the year etc.
- The load forecast in future years.

The Utility Loss Tariff is also time-of-use based (see section 7.6.1). The same structure (time interval, number of day types and number of seasons) is used for both the load model and Utility Loss Tariff. The time-of-use structure is determined by the requirements of both the load model and Utility Loss Tariff. For example referring to figure 7.4.1, if 6h intervals are

adequate for the Utility Loss Tariff but 1 hour intervals are required for the load model (technical loss, thermal and voltage drop calculations) then a 1 hour interval is used for both the load and Utility Loss Tariff models. In this example the Utility Loss Tariff must be implemented with a 1 hour interval (to coincide with the 1 hour interval of the load model) and the Utility Loss Tariff energy charges in time intervals 22-4, 4-16 and 16-22 are duplicated.

Figure 7.4.1: Example of load model and Utility Loss Tariff time interval interdependencies



A time interval of 1 hour is considered appropriate for this research as it coincides with the 1 hour intervals used in the Eskom Wholesale Electricity Pricing System (WEPS described in more detail in section 7.6.1) which is used as the Utility Loss Tariff. The method however supports any user defined time interval.

The day types differentiates between weekdays, Saturdays and Sundays as this is a common practice [Jardini et al, 1995], significantly reduces the standard deviation with non-domestic loads [Jardini et al, 1995], and coincides with the WEPS. The method however supports any user defined number of day types.

Seasonal variations are accounted for via 12 seasons i.e. a season for each month of the year. The method however supports any user defined number of seasons.

The consumer load shape is assumed constant in future years, and a per-unit forecast is used to account for changes in energy consumption and demand. Energy and demand are forecasted separately to cater for slight variations in load shape.

A forecast limit can be applied such that the load forecast is capped in a user specified year. As a result scenarios can be modelled where the additional load beyond a certain year is supplied by a network upgrade, and not by the original network.

#### 7.4.1 Domestic loads

South African domestic load research was described in section 2.4.9. Load data is available for the testing of domestic load profile models. The domestic load research recordings are current values (amps) and do not provide information on load power factor. An analysis of MV statistical metering information is required to get an approximation of South African low-income domestic consumer load power factors (see chapter 10) and establish if the variance in load power factor needs to be modelled.

The method builds on the existing load parameter forecasts described by Heunis and Dekenah [2001]. The prediction of load profile parameters for green-field projects is beyond the scope of this research, but is expected to be based on clustering techniques as described by Chicco et al [2005].

#### 7.4.2 Non-domestic loads

Load research into South African non-domestic loads usually found in close proximity to domestic loads was only recently started (2001), and the following can be observed [Herman, 2003]:

- Schools, clinics and shops are the main non-domestic loads being researched.
- The power factor of these non-domestic loads does not vary significantly and is very close to unity.
- Sensitivity analysis shows that mean loading is the most important load parameter and is far more significant than variance and power factor.
- The loads appear to be able to be classified based on floor area.
- There are significant differences between weekday, Saturday and Sunday loads. Differentiating between these day types (as is proposed) enhances accuracy.

- The sample size is small, and additional data is required before generalised load models can be determined.
- The loads exhibit characteristic seasonal variations and logger installation was directed to measure peak loadings. Loggers are only installed for fairly short durations (a few weeks). Recordings may not be suitable for load loss analysis over an extended time period.

## 7.5 TECHNICAL LOSS CALCULATION

Technical loss calculations are confined to load and no-load losses in transformers and load losses in conductors (cables/lines).

### 7.5.1 No-load losses

No-load losses are fixed. Changes due to voltage variations are not included. The total no-load loss is obtained by summation of the rated no-load losses of all transformers.

For the purposes of upstream loss calculation, no-load losses are represented as constant current loads. The load magnitude and power factor are dictated by the real and reactive components of the transformer rated no-load loss.

### 7.5.2 Load loss energy

Load losses are calculated using a statistical load model similar to Herman and Heunis [2002] (section 5.2.10) noting the following:

- The expected load loss energy is calculated in each time interval for each of the day types and seasons.
- Loads of different classes (Load Groups) are mixed assuming there is zero correlation between them within the time intervals. The accuracy of this assumption needs to be tested.
- The load power factor is catered for in the calculation of the mean current in each branch.
- Calculations are based on a constant current load model. The sensitivity of the results for this simplification/assumption needs to be tested for loads that are not constant current.
- Each Load Group has a forecasted change (increase) in energy and demand. The load profile is assumed to remain constant for the lifetime. A change in load shape due to the

unequal load growth of different Load Groups is accounted for in the derivation of the composite load forecasts (energy and demand). The accuracy of this technique needs to be tested.

- Shunt capacitors effects are included as constant current loads with unity leading power factor.

### 7.5.3 Load loss demand

The load loss demand is calculated in a user defined time interval and day type for each season of the year. The time interval and day type are the time period of maximum system demand, during which the utility pays maximum demand charges. The method uses the same load model as the load loss energy calculation. A percentile load loss demand is not required as expected values are used for planning and design purposes (as for load loss energy calculations).

## 7.6 TECHNICAL LOSS AND VOLTAGE DROP COSTING

Future technical loss costs and missed opportunity costs due to changes in revenue (due to voltage drop) are calculated as a Net Present Value. The lifetime capital, technical loss and voltage drop cost is obtained by summation of the initial capital cost and Net Present Value technical loss and voltage drop cost.

### 7.6.1 Utility Loss Tariff (generation/transmission costs)

In costing South African distribution technical losses, the upstream network and generation costs are based on the Eskom Wholesale Electricity Pricing System (WEPS) [Eskom, 2005a]. "*WEPS is designed as a cost-reflective tariff to recover the cost of energy (generation), network services (transmission) and other costs necessary to deliver a wholesale electricity service*" [Eskom, 2005a]. The WEPS tariff meets the requirements described in section 5.3.1, and has the following main characteristics for South African distribution technical loss costing (see appendix I for more detail):

- Time-of-use and seasonally differentiated energy charges (Rand/kWh) reflect the long-run marginal cost of generation for different times of the day (peak, standard and off-peak), days of the week (weekdays, Saturdays and Sundays) and seasons of the year (high demand and low demand seasons).

- Bulk transmission infrastructure costs are recovered by a transmission maximum demand charge (Rand/kVA).
- Transmission network load losses are recovered by multiplying the energy charges by a loss factor which is geographically differentiated to account for the transmission distances between the load and generation.
- The WEPS also includes customer service and administration charges, an electrification levy and a rural network levy. These cost components do not apply to technical losses and are excluded in technical loss evaluations.
- The WEPS does not charge for reactive power consumption during low season periods. Load power factors are assumed to be kept within acceptable limits via the enforcement of contractual power factor limits. This is appropriate for customer supplies. For loss assessment purposes the WEPS will be enhanced to incorporate the cost of reactive energy based on the lifetime cost of shunt capacitor banks, as suggested by Nickel and Braunstein [1981].
- The WEPS charges are updated annually. For loss costing purposes the structure of the tariff is assumed to remain constant. The future energy and demand charges will be increased in accordance with Eskom's forecasted tariff increases. These parameters are updated and published annually.
- The most significant change anticipated in the WEPS is the replacement of the energy tariff by market prices in a multi market model [Eskom, 2003a]. As long-run marginal costs should be used for loss evaluation, it is likely that the WEPS energy tariff will still be used for technical loss costing in a future multi market environment.
- The WEPS transmission charges are based on national averages. Full geographic differentiation of the transmission charges into 8 zones is planned to further improve cost reflectivity [Eskom, 2005a].

The WEPS tariff is appropriate for technical loss costing in South Africa as it accounts for the time-of-use energy cost of losses, and the infrastructure and loss costs in the upstream transmission networks.

The suitability of the WEPS is limited by the accuracy of the tariff charges. The assessment of the WEPS tariff charges is outside the scope of this research, and it is assumed that the charges are appropriate for application in South Africa.

Note that for the purposes of this research the WEPS tariff has been adopted as a Utility Loss Tariff for application in South Africa. The method is not restricted to the structure of the WEPS. The method is generic such that it can accommodate both energy and demand tariff

components for a user defined time interval, number of day types and number of seasons in the year. The energy tariff charges can be specified for each time interval and day type in each season of the year. The demand tariff charges can be specified for each season of the year. The method supports both time-of-use tariff structures with seasonal demand charges and two-part energy and demand charges. In the case of a fixed energy charge the time-of-use intervals required for the load profile model are still used, but all time-of-use energy charges will be the fixed energy charge. Conceptually the method can be applied with retail tariffs as paid by distribution utilities to generation/transmission. Alternatively a specific tariff appropriate for the costing of losses can be used. The method is only demonstrated using the WEPS tariff (as appropriate for application in South Africa), and is not limited to the WEPS tariff.

#### **7.6.2 Load voltage dependency and change in utility bulk energy purchases and utility revenue due to technical loss and voltage drop**

The need to consider load voltage dependency for the costing of load losses and voltage drop (change in utility bulk energy purchases and utility revenue) needs to be assessed. Errors may be large if load loss and voltage drop costs are based on constant power assumptions (the basis for present load loss costing techniques) and in reality loads are constant current or constant impedance (or a combination thereof). This is analysed in chapter 10.

There are two basic options for the assessment of conductor lifetime technical load loss and voltage drop costs considering load voltage dependency:

- 1) Develop a method to calculate the change in utility bulk energy purchases and change in consumer energy consumption for a given load voltage dependency (due to conductor voltage drop and technical load losses). Calculate the technical load loss cost and missed opportunity cost due to voltage drop using these calculated changes in utility bulk energy purchases, utility revenue and the Utility Loss Tariff and Customer Tariff.
- 2) Develop approximations between the change in utility bulk energy purchases, change in consumer energy consumption and change in technical load loss for different load voltage dependencies. Based on these approximations derive an effective cost of load loss energy (incorporating technical load loss cost and missed opportunity cost due to voltage drop) using the Utility Loss Tariff, Customer Tariff and load voltage dependency.

The 2<sup>nd</sup> option is preferred as the method can also be used to enhance present methods where the technical load loss is already calculated.

### 7.6.3 Total lifetime cost due to load losses and voltage drop

The technical load loss energy and demand in the various time periods are multiplied by the respective load loss costs (adjusted to include the effect of voltage drop and load voltage dependency) to calculate the normalised loss value (Rand/ohm) for each phase/neutral conductor of each branch. A normalised value is used because the branch resistance may not be specified (it is an output of the conductor size optimisation).

## 7.7 CONDUCTOR SIZE OPTIMISATION

The load loss calculations provide a normalised load loss cost (Rand/ohm) for each phase/neutral conductor of each branch. Given a set of cables/lines with their respective resistances, thermal ratings and capital costs, there are two conceptual alternatives for the selection of the optimal conductor size in each branch:

- 1) Calculate the lifetime cost (capital, load losses and voltage drop) of each cable/line in the set. Select the cable/line with the lowest lifetime cost.
- 2) Develop a regression relationship between the phase conductor resistance and capital cost. Calculate the ideal phase conductor resistance (average of the ideal conductor resistance for each phase) for minimum lifetime cost. Calculate the lifetime cost of the closest lower and higher phase conductor resistances in the cable/line set. Select the cable/line with the lower lifetime cost.

The number of cables/lines per voltage level and technology in a utility is typically less than 10, and in most cases less than 5 [Willis, 1997]. Alternative 1 is preferred as it is simpler to implement (regression is not required) and the number of calculations is not onerous. Alternative 1 also avoids possible errors in optimal conductor sizing in network branches supplying unbalanced load currents.

The following should be noted:

- The conductor size is optimised from the list of user specified cables/lines for a particular branch. If a single cable/line is specified in a branch then that cable/line is fixed and cannot be optimised. At least one cable/line must be specified per branch.

- A cable/line can only be selected as the optimum if its thermal rating is greater than the expected maximum load in that branch. Setting the thermal rating to a large value effectively disables the thermal loading checking.
- Cable/line sizing is based on the selection of single cables/lines. The paralleling of cables/lines is not considered but could be included if required.
- Only the conductor size is optimised and the optimisation is not constrained by the specification of a maximum voltage drop or minimum voltage limit. Voltage limits and additional optimisation variables could be included via constrained optimisation algorithms, but is beyond the scope of this research.

## 7.8 VOLTAGE DROP ASSESSMENT

### 7.8.1 LV voltage drop assessment

The QOS voltage drop assessment method is applied in LV networks for the following reasons:

- It is probabilistic and calculates the voltage drop for a user specified percentile and confidence level.
- The assessment closely aligns with the voltage criterion in the NRS 048-2 [2004].
- The load data is identical to that required for the loss calculation, with the addition of additional load parameters.
- The use of a percentile value enables the voltage drop to be calculated from load data based on a 1 hour time interval. With the Herman Beta method a method would need to be developed to estimate 5 or 10 minute load parameters in each 1 hour time interval. This would introduce additional errors.

Note that the Herman Beta method could be used, but would require additional development for the estimation of Herman Beta load parameters in different time periods.

It is possibly more important to understand the basis for the voltage drop calculation method than the selection of a particular method. The results must be interpreted correctly. In this research the voltage drop calculation is an output, and is not used to constrain the selection of the optimal conductor size. The voltage drop calculated in a network is dependent on the percentile and confidence level. Varying these parameters will result in significantly different voltage drops. It is critical that the values and meaning of both the percentile and confidence level are known and understood when interpreting the voltage drop calculation results. The

percentile refers to the probability that a particular voltage/load will not be exceeded due to load variations over time. The confidence level refers to the probability that the percentile value will not be exceeded due to uncertainties in customer loads within a homogeneous Load Group.

The following need to be tested/established for the QOS method:

- The suitability of the beta distribution used in the QOS method. The QOS method was developed for the analysis of voltages over weeks to months, and modifications may be required when applied to shorter time periods such as 1 hour intervals.
- Error levels due to the assumption of unity load power factor and ignoring network reactance.
- Error levels with load types that are not constant current.
- Error levels when mixing load types, with the assumption that there is zero correlation between load types within time intervals.

#### 7.8.2 MV voltage drop assessment

It is desirable if the deterministic techniques already available in utility and commercial load-flow software can be used for MV voltage drop assessment. As discussed in section 4.3.2, three deterministic options have been identified for evaluation.

The following need to be tested/established for deterministic MV voltage drop calculations:

- Error levels in each of the proposed deterministic options (see section 4.3.2).
- Sensitivity of results to network reactance, non-unity load power factor and load voltage dependency to establish the need to include these factors in MV voltage drop calculations.

#### 7.9 CONDUCTOR THERMAL LOADING ASSESSMENT

The thermal loading assessment provides an indication of conductor thermal loading. It is not within the scope of this research to develop or implement a thermal loading assessment method to accurately calculate conductor temperatures and/or insulation aging rates. The loading in each branch is calculated using the same load model as the load loss calculations. Conductor thermal ratings are user specified and fixed (no adjustment for local ambient

temperatures or load profiles). The thermal loading assessment is probabilistic to the extent that the load mean and variance are considered.

## 7.10 LOOKING FORWARD

A model has been proposed for the optimisation of South African domestic electrification conductor sizes to minimise the lifetime costs associated with conductor installation (capital), technical load losses and voltage drop (missed opportunity costs due to changes in consumer energy consumption and demand). The associated MV and LV voltage drops are calculated.

An analysis of MV statistical metering information is required to get an approximation of South African low-income domestic consumer load power factors and establish if the variance in load power factor needs to be modelled.

The load loss energy and demand calculations outlined in the chapter need to be developed further and tested via Monte Carlo simulation. The likely errors due to assumptions and simplifications need to be established. The method needs to be compared with the results of the Loss Load Factor and average profile load-flow methods.

A method needs to be developed to approximate the change in utility bulk energy purchases and change in consumer energy consumption from the conductor technical load loss and consumer voltage dependency. The approximation can then be used to derive an effective cost of conductor load loss energy incorporating conductor technical load loss cost and the missed opportunity cost due to conductor voltage drop.

The QOS LV voltage drop calculation needs to be tested within 1 hour time intervals. The likely errors due to assumptions and simplifications need to be established.

Three deterministic MV voltage drop calculation options need to be tested. The requirements to model MV network reactance, non-unity load power factor and load voltage dependency need to be tested.

## **8. SOUTH AFRICAN LOW-INCOME DOMESTIC CONSUMER POWER FACTORS**

In this chapter the power factor of South African low-income domestic consumer loads are estimated from MV load profile metering of active and reactive power. The results are used in the subsequent chapters.

### **8.1 BACKGROUND**

The Herman Beta and QOS voltage drop calculations assume that the domestic load power factor is unity. South African domestic load research only provides information on the consumer load current. The power factor is not measured.

The mean and variance of typical load power factors for rural domestic consumers (consumer load class Rural Settlement or Rural Village as per NRS034-1 [1999]) are required to assess the suitability and likely error range of power factor assumptions/simplifications in voltage drop and loss calculations.

Active and reactive power measurements of MV networks are available in Eskom Distribution, but include network losses. A method is required to extract the consumer load power factor from MV feeder load profile data.

### **8.2 METHOD FOR LOAD POWER FACTOR EXTRACTION**

The following method was used to extract the consumer load power factor from MV statistical load data:

- 1) Identify MV networks that almost exclusively supply low-income rural domestic consumers (Rural Settlement or Rural Village [NRS034-1, 1999]), where MV load profile data is available (30 minute averaging interval for both active and reactive power).

- 2) Filter out uncharacteristic load variations due to abnormal network events (outages, network switching and cold load pickup).
- 3) Perform MV network load-flow analysis. Scale customer loads to match the maximum recorded load (loads are assumed to be evenly distributed over the available MV/LV distribution transformation capacity).
- 4) Calculate the expected load and no-load loss at each of the time intervals. Subtract these losses from the MV load recordings to obtain the consumer active and reactive loads in each time interval.
- 5) Calculate the consumer load power factor mean and standard deviation in each hour of the day for each of the three day types (weekdays, Saturdays and Sundays).

Note this method adjusts the MV load recordings to account for losses in the MV network and MV/LV distribution transformers. LV networks are not included in the load-flow analysis, and the results ignore LV network losses. A sensitivity analysis on a range of possible LV loss values indicates that the errors (if LV losses are ignored) are low as LV losses are largely resistive due to the relatively low X/R ratio of LV networks.

### 8.3 RESULTS

Appendix B provides detailed results for two sample distribution networks in Eskom Distribution. A summary is provided in table 8.3.1. Both networks supply low-income domestic consumers commonly supplied by South African rural electrification networks.

Parameter	Network	
	Abattoir NB114	Abattoir NB115
Customers	Low-income rural domestic	Low-income rural domestic
Statistical metering period	15/04/2004 to 30/09/2004	15/04/2004 to 30/09/2004
Peak load	3959kVA	2353kVA
Average power factor	0.991	0.993
Weekday power factor mean at peak loading	0.997	0.995
Weekday power factor standard deviation at peak loading	0.001	0.001
Saturday power factor mean at peak loading	0.996	0.995
Saturday power factor standard deviation at peak loading	0.001	0.001
Sunday power factor mean at peak loading	0.997	0.995
Sunday power factor standard deviation at peak loading	0.001	0.001

Table 8.3.1: Summary of power factor analysis on sample networks

## 8.4 CONCLUSIONS

The following observations and conclusions can be made for the purposes of this research:

- The results are representative of the average power factor of South African low-income domestic consumers and minor non-domestic loads found in close proximity to these consumers. The power factor of individual loads may vary significantly from the values reported.
- The results are only valid for present consumption habits and appliances. A significant change, such as large-scale conversion from incandescent bulbs to compact fluorescent lamps (with their associated reduced power factor [Herman et al, 2006]), could change the results significantly.
- The average power factor for all time intervals and the power factor at peak loading are close to unity.
- The coefficient of variation of the power factor in each time interval is less than 1.2%, and drops to less than 0.2% during peak loading intervals. These low values indicate that for the purposes of loss and voltage drop calculations, the variance in the load power factor can be ignored (raised in section 7.4.1).
- The power factor mean and variance are similar for different days of the week.

## 8.5 LOOKING FORWARD

The typical low-income domestic consumer load power factors will be applied in subsequent testing and development.

The variance of the low-income domestic consumer load power factor appears to be small. The variance of load power factor will not be included in technical load loss and voltage drop calculations.

## **9. SOUTH AFRICAN RURAL DOMESTIC ELECTRIFICATION NETWORK PARAMETER SENSITIVITY**

Errors in network voltage drop and technical loss calculations arise due to simplifications made in the calculations and uncertainty in the magnitudes and statistical properties of assumed loads, including uncertainty in the load voltage dependency. A representative South African rural electrification network is analysed to provide guidance on the acceptability of certain simplifications/assumptions used in voltage drop and loss calculations, the likely error ranges associated with these simplification/assumptions and the sensitivity of voltage drop and loss calculations to load voltage dependency.

The results and recommendations of this analysis are used in the loss and voltage drop calculations utilised for this research.

This core issues in this chapter are published by Carter-Brown and Gaunt [2005a].

### **9.1 BACKGROUND AND OBJECTIVE**

The method for conductor size optimisation uses loss and voltage drop calculations. Errors in these calculations arise due to:

- The simplifications made in the calculations e.g. that load power factor and network reactance can be ignored in domestic LV voltage drop calculation.
- The uncertainty of the magnitudes and statistical properties of assumed loads, including uncertainty in the load voltage dependency (typically characterised as constant power, constant current, constant impedance or a combination thereof).

The acceptability of certain simplifications/assumptions used in MV and LV voltage drop and loss calculations needs to be assessed. The likely error ranges associated with these

simplification/assumptions and the sensitivity of voltage drop and loss calculations to load voltage dependency also needs to be assessed.

An analysis of a sample (representative) South African rural domestic electrification network is performed to test the objectives listed in table 9.1.1.

<b>Analysis</b>	<b>Objective</b>
Sensitivity of MV voltage drop to network reactance and non-unity load power factor.	Test the assumption that MV voltage drop calculation must consider network reactance and load power factor (i.e. that network reactance and load power factor can't be ignored). Establish the error range if network reactance and load power factor are ignored in MV voltage drop calculation.
Sensitivity of LV voltage drop to network reactance and non-unity load power factor.	Test the assumption that LV voltage drop calculation does not need to consider network reactance and load power factor. Establish the error range if network reactance and load power factor are ignored in LV voltage drop calculation.
Sensitivity of MV and LV voltage drops to load voltage dependency.	Test the assumption that MV and LV voltage drop calculation can be based on a constant current load model. Establish the error range if loads are not constant current.
Sensitivity of MV and LV technical load loss (energy and demand) for different load voltage dependencies.	Test the assumption that MV and LV technical load loss calculations can be based on constant current load models. Establish the error range if loads are not constant current.
Sensitivity of MV and LV voltage drop and load loss to load magnitude, line lengths and line models.	Test the suitability of calculation simplifications and the need to model load voltage dependency given that there may be considerable uncertainty in the magnitude of the load and network characteristics.

**Table 9.1.1: Rural electrification network analysis and sensitivity study objectives**

The sensitivity of distribution network load-flow results to load voltage dependency has been assessed on an IEEE 12.66kV 32 branch test network [Stojanovic et al, 1999]. The results are not directly applicable to South African networks due to the considerable differences in network and load characteristic. The analysis by Stojanovic et al [1999] only considered the MV network and load-flow sensitivity to load voltage dependency.

The MV and LV networks should be modelled in the same study so that the interaction between these two network levels can be assessed (parameter changes in the one network level impact the other). For the purposes of this analysis a combined MV and LV distribution network is required. The parameter sensitivities also need to be performed for a range of parameters for which there may be considerable uncertainty. This enables the likely errors in any simplifications/assumptions to be assessed in the context of other likely sources of error.

## 9.2 SOUTH AFRICAN RURAL DOMESTIC ELECTRIFICATION NETWORK

The sample network shown in figure 9.2.1 has the following characteristics which are considered representative of South African rural domestic electrification:

- The overhead 22kV three phase delta MV primary supplies 22kV phase-to-phase and 19kV Single Wire Earth Return (SWER) MV laterals.
- The networks supplies 2188 low-income domestic customers with an ADMD of 0.55kVA per customer and load characteristic in figure 9.2.2 as recorded in Eskom Distribution and detailed in appendix B.
- Fixed tap 16kVA single phase and 32kVA bi-phase transformers supply 460/230V LV distribution.
- LV networks are comprised of overhead Aerial Bundle conductors and Airdac service conductors.

Tables 9.2.1 and 9.2.2 provide details on the transformer and line characteristics as used in Eskom Distribution.

Voltage and technology	Rating [kVA]	Z +ve [%]	X/R +ve [ratio]	Rated core loss [kW]	Number installed	Installed capacity [kVA]
22kV/19kV (SWER)	400	5.08%	3.44	5.67	2	800
22kV/19kV (SWER)	200	4.60%	2.76	3.13	1	200
22kV/480V (Bi-phase)	32	4.17%	2.08	0.67	23	736
22kV/240V (Single phase)	16	4.17%	1.31	0.41	13	208
19kV/480V (Bi-phase)	32	4.17%	1.74	0.67	34	1088
19kV/240V (Single phase)	16	3.72%	1.26	0.37	28	448
<b>Total</b>					<b>101</b>	<b>3480</b>

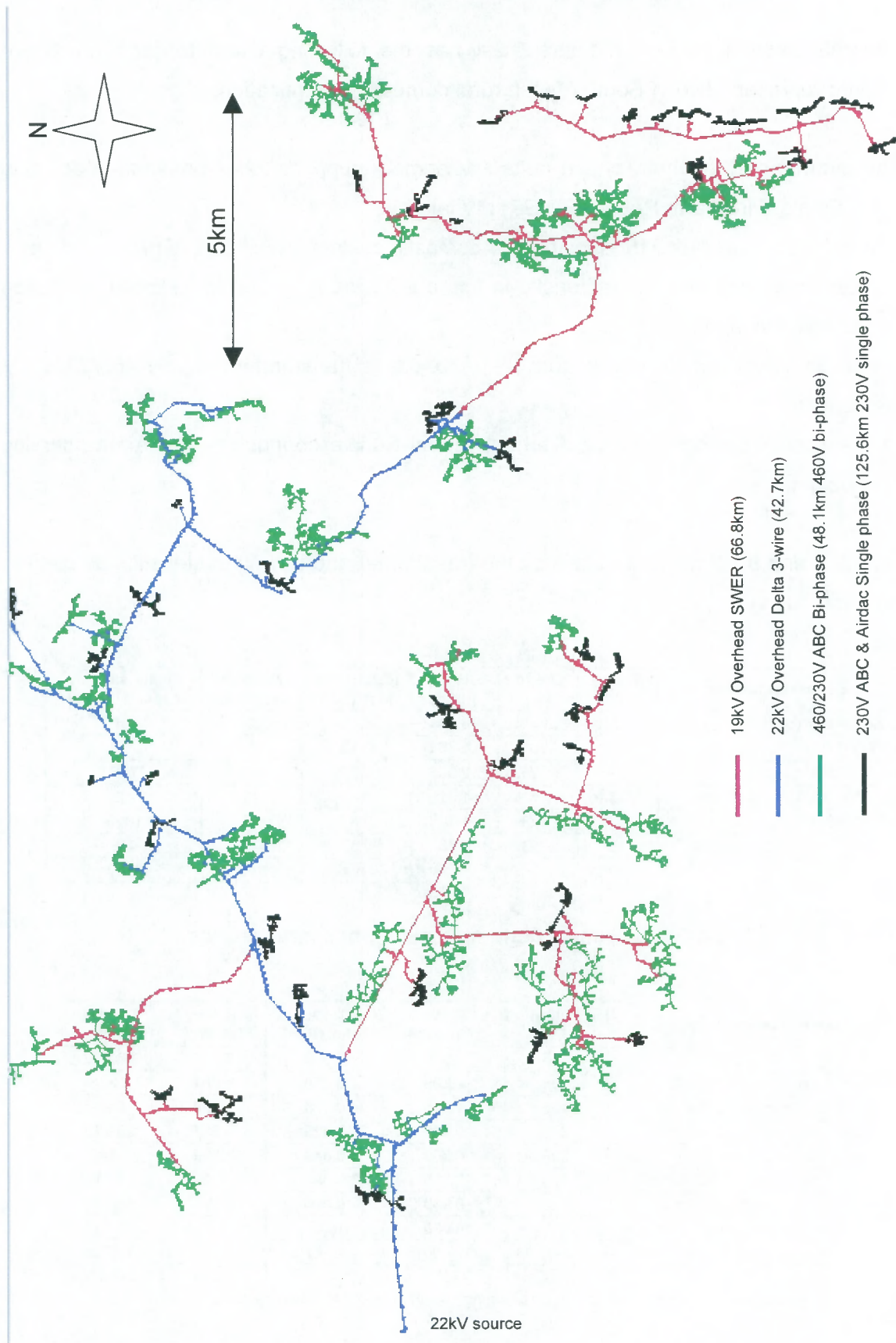
Table 9.2.1: Sample network transformer characteristics

Voltage and technology	Rating [A]	R +ve [ohms/km]	X +ve [ohms/km]	B +ve [uS/km]	Length [km]
19kV SWER Squirrel	105	1.553	0.809	2.022	66.842
22kV Three phase Squirrel	105	1.505	0.360	3.201	2.386
22kV Phase-to-phase Squirrel	105	1.505	0.378	3.038	13.933
22kV Three phase Mink	209	0.500	0.325	3.557	26.288
22kV Phase-to-phase Mink	209	0.500	0.344	3.359	0.140
230V Single phase ABC 35mm <sup>2</sup>	120	0.938	0.096	0 (2)	61.112
460V Bi-phase ABC 35mm <sup>2</sup>	120	0.938	0.096	0 (2)	48.101
230V Single phase Airdac 4mm <sup>2</sup>	37	4.990	0 (1)	0 (2)	64.197
230V Single phase Airdac 10mm <sup>2</sup>	65	2.000	0 (1)	0 (2)	0.275
<b>Total</b>					<b>283.274</b>

(1) Reactance in service cables and (2) charging capacitance of LV networks has been ignored

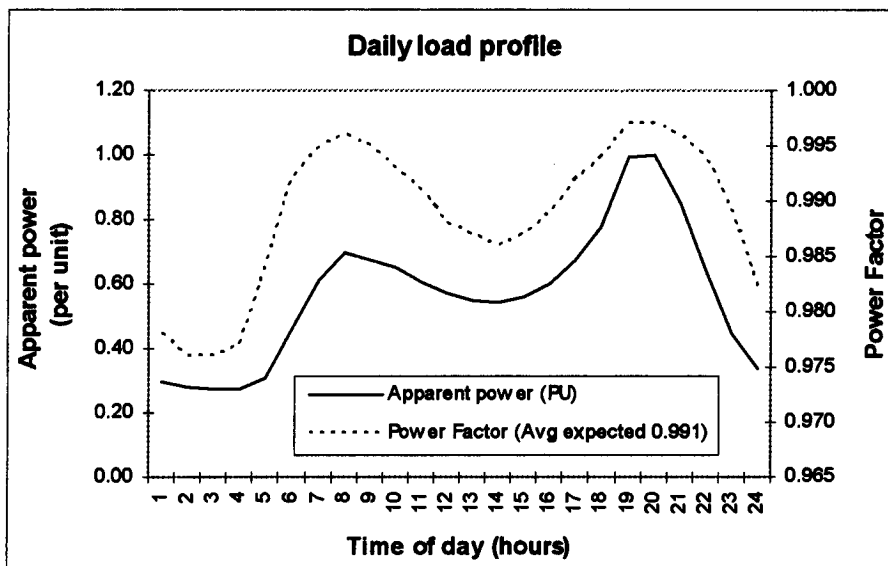
Table 9.2.2: Sample network line characteristics

Figure 9.2.1: Sample rural domestic electrification network



The combined MV and LV network, including all service connections, was modelled in DigSilent Power Factory for unbalanced load-flow analysis. The load-flow results are summarised in table 9.2.3, and are based on constant current load models, rated impedances, expected load power factor and load magnitude, reasonable phase balancing (network and load phasing was assigned to minimise voltage unbalance) and the operation of all transformers on nominal tap. Maximum loading occurs at 19:00. Percentage voltages are on a voltage base of 22kV (MV three phase and phase-to-phase), 19kV (MV SWER) and 230V (LV).

Figure 9.2.2: Typical low-income domestic daily load profile



Network characteristic	Value
Maximum MV voltage drop [%]	5.77%
Maximum MV/LV transformer voltage drop [%]	3.25%
Maximum LV voltage drop [%]	3.80%
Sum of maximum % voltage drops [%]	12.81%
Peak load [kW]	1206.77
Average load power factor	0.991
Maximum load loss demand [kW]	73.50
No-load loss demand [kW]	18.28
Peak demand per consumer [kW]	0.55
Total loss demand as % of peak load	7.60%
Monthly load energy [MWh]	396.56
Monthly load loss energy [MWh]	11.81
Monthly no-load loss energy [MWh]	13.16
Total loss energy as % of load energy	6.30%
Monthly load energy per consumer [kWh]	181

Table 9.2.3: Sample rural domestic electrification network characteristics

The load model is based on average loading in 1 hour intervals. The variance of the load within 1 hour intervals is ignored. The stochastic nature of the load is not modelled and voltage drops and load losses are understated. Average loads are however adequate for the sensitivity studies described in this chapter as the change in results (not the absolute values of the results) is of interest.

### 9.3 NETWORK AND LOAD PARAMETER SENSITIVITY

The parameters selected for the sensitivity analysis and the rationale therefore are listed in table 9.3.1.

Parameter	Range	Rationale
Load voltage dependency	K = 1 (expected) K = 0 K = 0.5 K = 1.5 K = 2	Analysis of extensive load data collected in South Africa validates the assumption that domestic electrical loads can be modelled as constant current sinks for voltage drop calculations [NRS 034-1, 1999]. It is unlikely that domestic loads are at the extremes of constant power or constant impedance, but could be a combination thereof. The load voltage dependency can be expressed as $S_v = S_{rated} \cdot V_{pu}^K$ where K = 0 constant power, K = 1 constant current, K=2 constant impedance. For example K = 0.5 is a combination of constant power and constant current.
Load power factor	PF1 = 0.991 (expected) PF2 = 0.980 PF3 = 0.960	The expected power factor is based on the results in chapter 8. Two other power factors are used to assess the impact of reduced power factor due to motor loads usually associated with higher income domestic consumers.
Load magnitude	100% (expected) 80% 120%	The expected load magnitude is based on the South African Domestic Load Research program, and specifically the expected maximum loading for low income rural domestic consumers [NRS 034-1, 1999]. Variations in load magnitude arise due to uncertainty in consumer numbers and characteristics.
Network reactance	100% (expected) 50% 150%	The expected network reactance is based on Eskom Distribution equipment specifications and typical line designs. Variations in reactance arise due to the use of different line technologies (overhead versus cable) and line configurations (conductor spacing).
Line length	100% (expected) 90% 110%	The expected line lengths are based on CAD layouts of the distribution network. Variations in line length arise due to errors in data capture and difference between the designed and as-built networks.
Line configuration	Delta (expected) Horizontal	The expected three phase MV line impedances are based on a delta conductor configuration. Different line structures are used depending on conductor sizes and span lengths. The impact of a horizontal line configuration is assessed.

Table 9.3.1: Parameters included in the sensitivity analysis

The detailed parameter sensitivity results are tabled in appendix C.

### 9.4 MODELLING NETWORK REACTANCE AND LOAD POWER FACTOR

Figure 9.4.1 summarises the errors in the LV voltage drop calculation if network reactance and load power factor are ignored, for the three ranges of power factor and reactance. For the purposes of simplification a constant current load model is used. The error range is small and indicates that the simplifications for reactance and power factor used in the Herman

Beta and QOS LV voltage drop assessment methods are valid for practical analysis purposes.

Figure 9.4.1: LV voltage drop error  
(power factor and reactance are ignored, constant current load model)

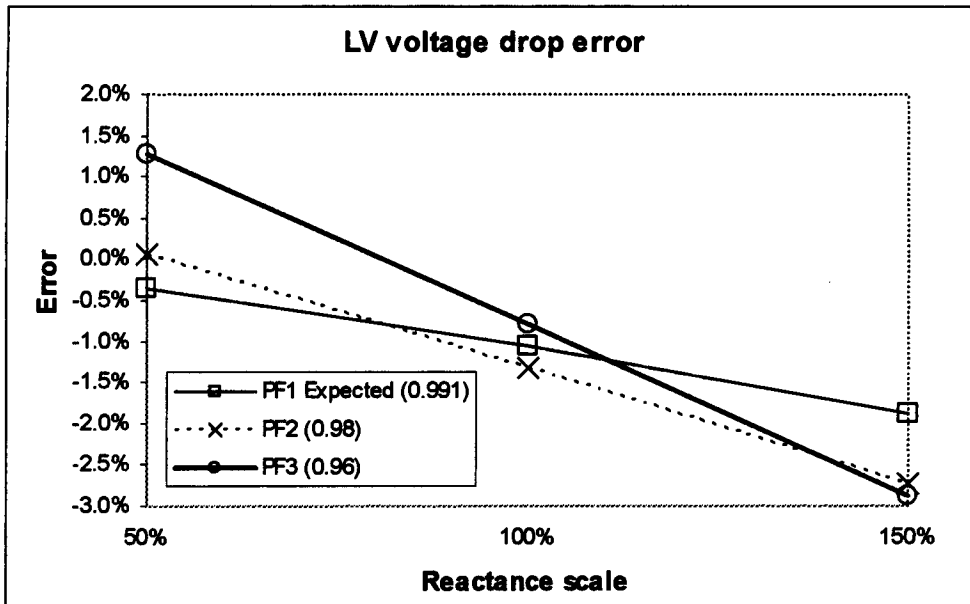
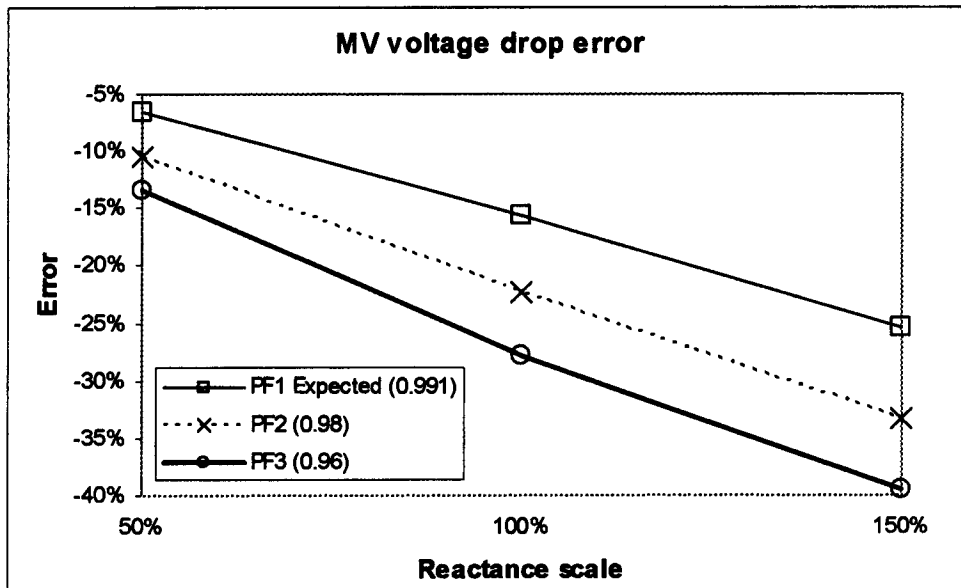


Figure 9.4.2: MV voltage drop error  
(power factor and reactance are ignored, constant current load model)

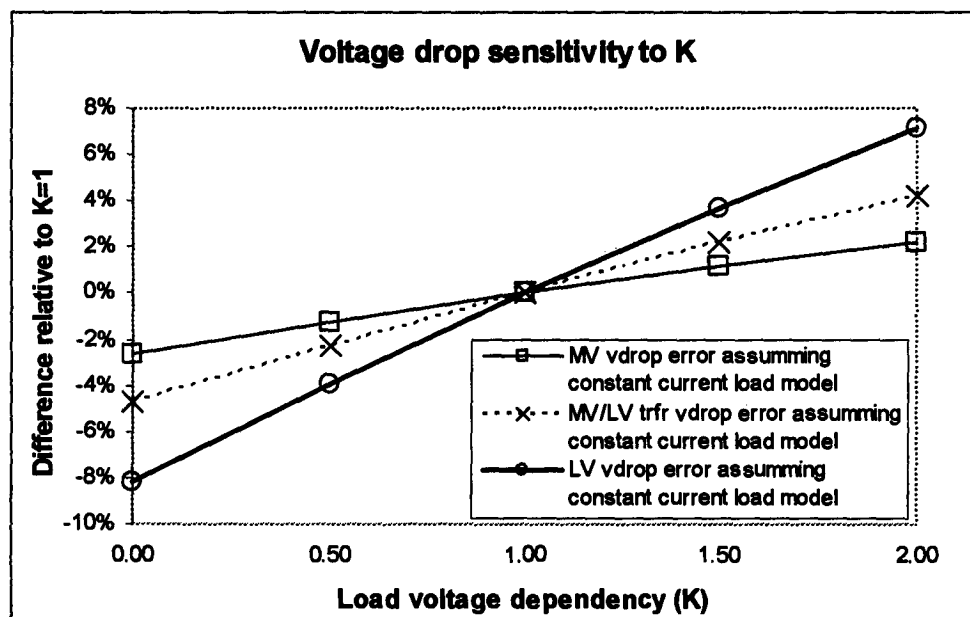


The error in the MV voltage drop is summarised in figure 9.4.2. Error levels are significantly higher in MV networks due to the increased X/R ratio. Similar errors are obtained for MV/LV transformers. The results indicate that network reactance and load power factor cannot be ignored for MV network and MV/LV transformer voltage drop analysis.

## 9.5 VOLTAGE DROP AND LOAD LOSS SENSITIVITY

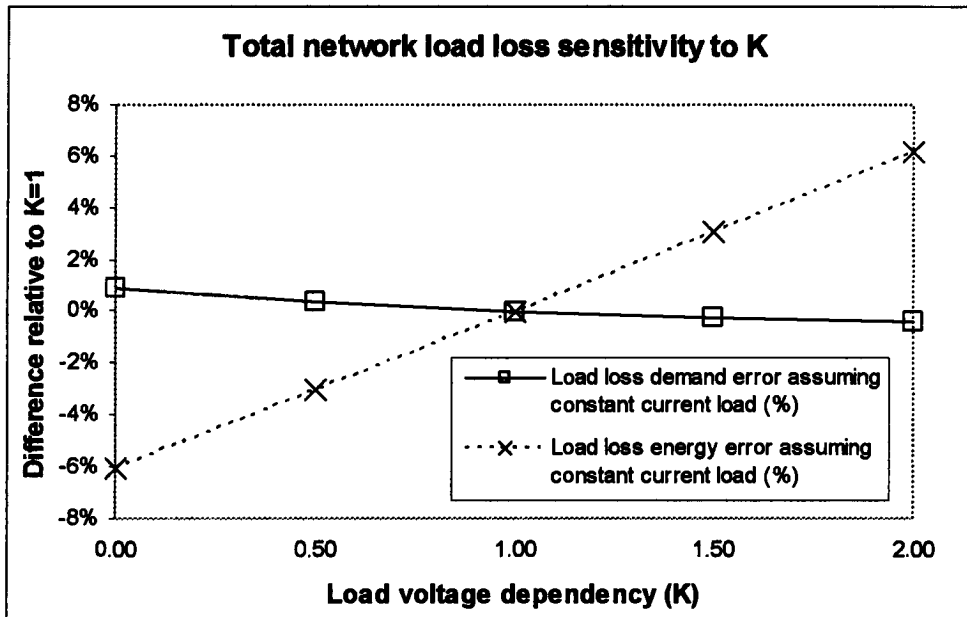
Figure 9.5.1 illustrates the MV, MV/LV transformer and LV voltage drop sensitivity for different load voltage dependencies (using expected load power factor and network reactance). The error levels for moderate deviations from constant current ( $K = 0.5$  to  $1.5$  as per table 9.3.1) are relatively small and within practical design requirements.

Figure 9.5.1: Voltage drop sensitivity to load voltage dependency (expected reactance and power factor)



The change in load loss demand and load loss energy (figure 9.5.2) for different load voltage dependencies is relatively small for moderate deviations from constant current, and indicates that load loss analysis is not very sensitive to K (given the expected voltage drops and voltage control). In this particular example, load loss energy decreases with constant power loads as the MV voltage control and use of 240V transformers results in customer voltages greater than 230V for the majority of the customer supplies and daily load cycle.

Figure 9.5.2: Load loss demand and load loss energy sensitivity to load voltage dependency (expected reactance and power factor)



The results of the sensitivity analysis for variations in load magnitude, line length and line configuration are summarised in table 9.5.1 (constant current loads and the expected reactance and power factor are used).

Parameter		Change in voltage drop	Change in load loss demand	Change in load loss energy
Load magnitude	80%	-20.28%	-36.00%	-35.87%
	120%	20.56%	44.02%	43.92%
Line length	90%	-5.61%	-6.54%	-6.59%
	110%	5.60%	6.54%	6.62%
Line configuration: Horizontal		0.29%	0.01%	-0.01%

Table 9.5.1: Voltage drop and load loss sensitivity to load magnitude, line length and line configuration

The results indicate that while an accurate network model is important, the largest source of possible errors is likely to be in the assumed load magnitude, especially given that there can be large differences between the expected loads (during planning and design) and the actual loads. Analysis results are insensitive to MV line configurations (delta versus horizontal).

## 9.6 CONCLUSIONS AND LOOKING FORWARD

The following conclusions can be made for South African electrification network analysis, and will be applied in the model outlined in chapter 7:

- Network reactance and load power factor can be ignored for domestic LV voltage drop calculation (raised in sections 4.2.1 and 7.8.1).
- Network reactance and load power factor must be included in MV network and MV/LV transformer voltage drop calculation (raised in sections 4.3.1 and 7.8.2).
- Voltage drop and loss calculations are not sensitive to load voltage dependency. Constant current load models are appropriate and error levels with loads that are not constant current are acceptable (raised in sections 4.4, 7.5.2 and 7.8.1).
- Assumptions for load magnitude are likely to be the largest source of error. Efforts to improve load modelling and forecasting are well justified.

## **10. LOAD VOLTAGE DEPENDENCY AND CHANGES IN UTILITY BULK ENERGY PURCHASES AND CHANGES IN CONSUMER ENERGY CONSUMPTION AND DEMAND**

Referring to section 7.6.2, a method is required to account for the effect of load voltage dependency, conductor load losses and conductor voltage drop on utility bulk energy purchase costs and utility revenue. In this chapter an approximate relationship between conductor load loss and change in consumer energy/demand is used to derive an equivalent load loss cost that incorporates the cost of technical load losses and the missed opportunity cost due to a reduction in consumer energy consumption/demand as a result of conductor voltage drop. The method is tested on a case network to establish the accuracy of the approximations used, and the error levels if changes in consumer energy/demand (due to conductor voltage drop) are ignored.

The core issues in this chapter are published by Carter-Brown and Gaunt [2005b].

### **10.1 COMBINING TECHNICAL LOAD LOSSES AND VARIATIONS IN CUSTOMER LOAD**

As will be shown, technical load losses, utility bulk energy purchases and utility revenue are related in passive distribution networks (without active or automatic voltage control between the branch under study and the customer loads). This relationship can be used to improve present load loss costing methods such that the effective cost of load losses can be adjusted to include the effect of voltage drop and load voltage dependency on consumer energy consumption and demand.

Ignoring demand costs and other costs not directly related to the purchase of bulk energy, the Net Profit [Rand] of the distribution utility is the difference between energy sales income and energy purchase costs, and is given by:

$$\begin{aligned} NP &= CT_{ac} \cdot (E_b - E_v) - ULT_{ac} \cdot (E_b - E_v + L_{ne}) \\ &= E_b \cdot (CT_{ac} - ULT_{ac}) - E_v \cdot (CT_{ac} - ULT_{ac}) - L_{ne} \cdot ULT_{ac} \end{aligned} \quad 10.1.1$$

NP Net Profit [Rand]  
 ULT<sub>ac</sub> Utility Loss Tariff active energy charge [Rand/kWh]  
 CT<sub>ac</sub> Customer Tariff active energy charge [Rand/kWh]  
 E<sub>b</sub> Customer base energy consumption assuming zero voltage variation [kWh]  
 E<sub>v</sub> Reduction in customer energy consumption due to voltage variation [kWh]  
 L<sub>ne</sub> Network technical loss energy [kWh]

The decrease in Net Profit [Rand] due to the technical load loss and the reduction in revenue caused by the voltage drop in a branch is given by:

$$DNP = E_v \cdot (CT_{ac} - ULT_{ac}) + L_{neL} \cdot ULT_{ac} \quad 10.1.2$$

DNP Decrease in Net Profit due to technical load loss and reduction in revenue [Rand]  
 L<sub>neL</sub> Network technical load loss energy [kWh]

In passive networks the expected change in active energy consumption can be approximated from the load loss energy (the accuracy of this approximation is tested in the case study):

$$E_v \approx K_e \cdot L_{neL} \quad 10.1.3$$

In loadflow the load magnitude including voltage variation  $S = S_{rated} \cdot V_{per\ unit}^{K_e}$

K<sub>e</sub> Per-unit change in customer active energy consumption for a per-unit change in voltage [ratio]

This approximation is based on two assumptions/simplifications:

- 1) It assumes that K<sub>e</sub> does not vary with the magnitude of the consumer voltage i.e. that the relationship between the change in voltage and change in energy consumption is linear.

For large voltage variations and load types towards the extreme of constant impedance, the error level could be significant.

- 2) The relationship is only strictly valid for unity power factor loads in networks with no inductance (only resistance). The error level in South African domestic electrification networks needs to be assessed.

Substituting equation 10.1.3 into equation 10.1.2, the cost of load loss energy [Rand/kWh] in a conductor (incorporating the effect of voltage drop and load voltage dependency on consumer energy consumption) is approximated by:

$$\begin{aligned}
 \text{CLLE} &\approx \text{ULT}_{\text{ac}} \cdot (1 - K_e) + K_e \cdot \text{CT}_{\text{ac}} \\
 &\approx \text{ULT}_{\text{ac}} && \text{for constant power loads as } K_e = 0 \\
 &\approx \text{CT}_{\text{ac}} && \text{for constant current loads as } K_e = 1 \\
 &\approx 2 \cdot \text{CT}_{\text{ac}} - \text{ULT}_{\text{ac}} && \text{for constant impedance loads as } K_e = 2
 \end{aligned}
 \tag{10.1.4}$$

**CLLE** Cost of technical load loss energy incorporating voltage drop and load voltage dependency [Rand/kWh]

By specifying the load energy voltage dependency constant  $K_e$ , the load loss energy cost is based on both the Utility Loss Tariff (generation/transmission) and Customer Tariff. The load loss energy cost accounts for the effect of load energy voltage dependency on the energy supplied by the upstream network/generation (utility bulk energy purchase cost) and consumer energy consumption (utility revenue).

Note that the load loss still needs to be calculated. The method simply enhances existing load loss costing practices by calculating a composite load loss energy cost [Rand/kWh].

The load energy voltage dependency ( $K_e$ ) refers to the effect of voltage variations on consumer energy consumption over long periods of time (weeks to months). The long term behaviour of loads is influenced by the affordability of the electrical energy to the customers [Gaunt, 2003]. For example very poor customers using as little as 25kWh per month constrained by the cost of electricity will not change their consumption as a result of a change in voltage (they appear as constant power/energy loads). Much larger energy consumers (for whom the consumption of electricity is less price elastic) will be more affected by the voltage and  $K_e$  will accordingly be higher.

Referring to equation 10.1.4, for constant power ( $K_p=0$ ) and constant current ( $K_c=1$ ) customers the technical load loss energy cost is only dependent on the Utility Loss Tariff and Customer Tariff respectively. The technical load loss energy cost of networks supplying customers that are not either constant power or constant current is a function of both the Utility Loss Tariff and Customer Tariff.

The cost of load loss demand [Rand/kW] in a conductor (incorporating the effect of voltage drop and load voltage dependency on consumer demand) is approximated by:

$$\begin{aligned}
 \text{CLLD} &\approx \text{ULT}_{\text{ad}} \cdot (1 - K_d) + K_d \cdot \text{CT}_{\text{ad}} \\
 &\approx \text{ULT}_{\text{ad}} && \text{for constant power loads as } K_d = 0 \\
 &\approx \text{CT}_{\text{ad}} && \text{for constant current loads as } K_d = 1 \\
 &\approx 2 \cdot \text{CT}_{\text{ad}} - \text{ULT}_{\text{ad}} && \text{for constant impedance loads as } K_d = 2
 \end{aligned}
 \tag{10.1.5}$$

**CLLD** Cost of technical load loss demand incorporating voltage drop and load voltage dependency [Rand/kW]

**ULT<sub>ad</sub>** Utility Loss Tariff active demand charge [Rand/kW]

**CT<sub>ad</sub>** Customer Tariff active demand charge [Rand/kW]

**K<sub>d</sub>** Per-unit change in customer active power demand for a per-unit change in voltage [ratio]

The load loss demand cost accounts for the effect of load demand voltage dependency on the demand supplied by the upstream network/generation (utility bulk demand purchase cost) and consumer demand (utility revenue in cases where consumers pay demand charges).

The load demand voltage dependency ( $K_d$ ) refers to the effect of voltage variations on consumer demand over short periods of time (minutes to hours), and is not expected to be influenced by price elasticity. The short term demand will be dictated by the appliance characteristics.

Equation 10.1.5 assumes that the time of system maximum demand and customer maximum demand coincide. This equation can still be used with non-coincident system and customer maximum demands provided the Utility Loss Tariff and Customer Tariff demand charges are adjusted accordingly; at the time interval of maximum system demand the Customer Tariff maximum demand charge will effectively be zero, and at the time interval of maximum customer demand the Utility Loss Tariff maximum demand charge will effectively be zero.

The total load loss demand cost is obtained by adding the load loss demand costs for the system and customer maximum demand time intervals.

Eskom Customer Tariff demand charges are based on apparent power [Eskom, 2005b]. An apparent power charge [Rand/kVA] can be used for  $ULT_{ad}$  assuming that the demand voltage dependency is the same for real and reactive power. Errors are introduced if the real and reactive demand voltage dependencies differ and the load power factor is non-unity. Errors and adjustments due to apparent power demand tariffs are discussed further in section 11.2.1.

If customers do not pay a demand charge (as with South African domestic consumers [Eskom, 2005b]) then equation 10.1.5 simplifies as follows:

$$\begin{aligned}
 CLLD &\approx ULT_{ad} \cdot (1 - K_d) \\
 &\approx ULT_{ad} && \text{for constant power loads as } K_d = 0 \\
 &\approx 0 && \text{for constant current loads as } K_d = 1 \\
 &\approx -ULT_{ad} && \text{for constant impedance loads as } K_d = 2
 \end{aligned}
 \tag{10.1.6}$$

## 10.2 CASE STUDY

The following case study is used to test the accuracy of the proposed method and illustrate the errors that may arise in traditional technical load loss costing techniques that ignore changes in customer energy consumption and demand.

The proposed method is implemented using a constant current load model for the calculation of load losses. Only the cost of the load loss is influenced by  $K$  (the technical load loss remains constant). This is expected to provide acceptable accuracy as the magnitude of load loss is not expected to vary significantly for different load voltage dependencies (see section 9.5). The effective cost of the load loss incorporating the cost of voltage drop is however expected to be sensitive to load voltage dependency.

The test network (table 10.2.1) is a three phase four wire 400/230V LV feeder supplying 5kVA domestic loads at six nodes 100m apart. Three cable sizes are available for selection (table 10.2.2). For simplification the analysis is confined to a weekday. The domestic weekday load profile and power factor are illustrated in figure 10.2.1, as recorded in Eskom Distribution and detailed in appendix B.

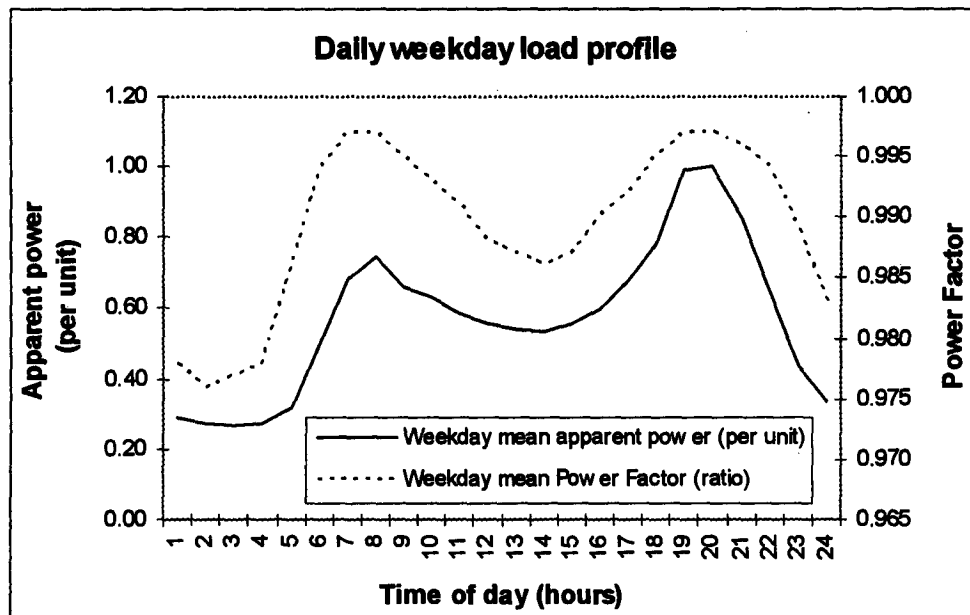
Phase	Node					
	1	2	3	4	5	6
A	5					5
B		5			5	
C			5	5		

Table 10.2.1: Case study network (load in kVA at nominal voltage). Nodes are 100m apart

Conductor	Phase		Neutral	
	R [ $\Omega$ /km]	X [ $\Omega$ /km]	R [ $\Omega$ /km]	X [ $\Omega$ /km]
70mm <sup>2</sup> ABC	0.479	0.089	0.778	0.089
50mm <sup>2</sup> ABC	0.693	0.090	0.778	0.090
35mm <sup>2</sup> ABC	0.938	0.096	1.065	0.096

Table 10.2.2: Case study network conductor impedances

Figure 10.2.1: Domestic weekday apparent power load profile and power factor

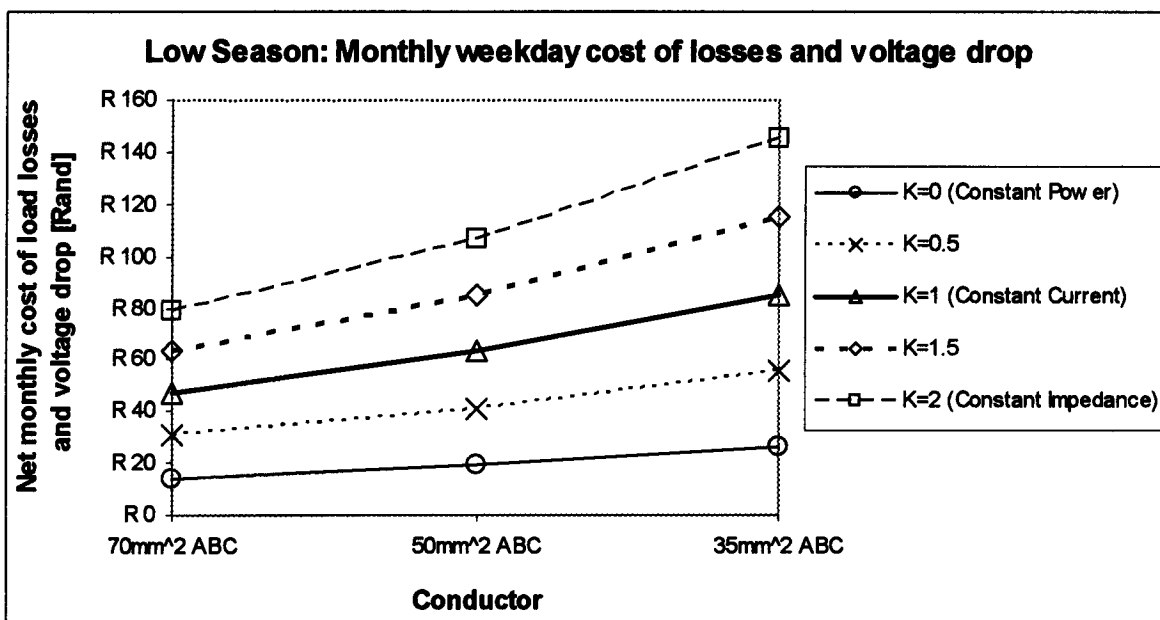


Multiple 1 hour time interval unbalanced load-flow analysis was performed using DigSilent Power Factory for five different load voltage dependency factors  $K = K_a = K_d = 0, 0.5, 1, 1.5$  and 2. The load-flow results are summarised in appendix D, table D.1.

The analysis only considers the mean load. The load variance is ignored and the losses and voltage drop are understated. The absolute values are hence not representative of practical networks. The differences in the load-flow results for different load voltage dependencies and conductor sizes is however sufficient for illustrative purposes and testing.

The utility energy and demand charges (Utility Loss Tariff) are based on the Eskom 2005 Wholesale Electricity Pricing System (WEPS) tariff [Eskom, 2005a]. WEPS has a monthly demand charge, and a time-of-use energy charge differentiating between three time periods and two annual seasons as detailed in appendix I. The consumer energy charge (Customer Tariff) is 40.68c/kWh (a single-part fixed rate energy charge), and is based on the Eskom 2005 Homelight 1 tariff, as commonly applies to low-income domestic supplies in South Africa [Eskom, 2005b]. There is no customer demand charge.

Figure 10.2.2: Low season cost of load losses (energy and demand incorporating changes in revenue due to voltage drop and load voltage dependency) according to cable size (actual, as calculated from load-flow)



35mm <sup>2</sup> ABC conductor	Load voltage dependency				
	K = 0	K = 0.5	K = 1	K = 1.5	K = 2
Cost per kWh of weekday technical load loss energy, including the effect of the change in revenue [Rand/kWh]. This is the actual cost as calculated via load-flow	R 0.13 (R 0.31)	R 0.26 (R 0.36)	R 0.41 (R 0.41)	R 0.55 (R 0.46)	R 0.70 (R 0.51)
Error in estimated cost of monthly weekday load loss energy and demand assuming a constant power load model and ignoring changes in revenue [% error as compared to actual via load-flow]	0.00% (0.00%)	-50.60% (-9.94%)	-66.63% (-18.01%)	-74.52% (-24.70%)	-79.21% (-30.33%)
Error in estimated cost of monthly weekday load loss energy and demand using the proposed method and a constant current load model for loss calculation [% error as compared to actual via load-flow]	-7.75% (-8.07%)	-3.02% (-3.55%)	0.23% (0.26%)	3.06% (3.51%)	5.70% (6.35%)

Table 10.2.3: 35mm<sup>2</sup> ABC conductor summary results. High and Low season WEPS results are provided with and without brackets respectively. (R6≈1US\$)

The cost evaluation results are detailed in appendix D, table D.2. The comparison of monthly load loss costs for each of the cables and the summary results for the 35mm<sup>2</sup> ABC conductor are provided in figure 10.2.2 and table 10.2.3 respectively. The following can be observed:

- The upstream (generation/transmission) cost of technical load loss energy (Rand/kWh) does not change with the value of K. The effective cost of technical losses varies due to voltage drop and the change in customer energy and demand as K changes.
- The effective cost per kWh of technical load loss energy (including the effect of the change in customer energy and demand) varies significantly according to the model of the load and its sensitivity to changes in voltage.
- Assuming all revenue is collected (zero non-technical losses) the consideration of changes in revenue increases the effective cost of technical load losses, and has implications for network planning and design.
- If load loss cost evaluations are based on constant power loads and ignore changes in revenue due to voltage drop, the errors can be large for loads significantly different to constant power (raised in section 5.3.2).
- Errors in the traditional (constant power) approach increase with the increasing differential between the Utility Loss Tariff and Customer Tariff. As a result the errors in the WEPS low season are higher than the errors in the WEPS high season.
- The proposed method (implemented using a constant current load model for the calculation of load loss) is accurate if the load behaves as a constant current when the voltage changes. For loads that behave as constant power, the method understates the load loss cost by a maximum of 8.07%. For all other load behaviour, the errors in the proposed method are significantly less (-4% to 6%) than for traditional methods based on constant power assumptions, with errors of up to -79%.

### 10.3 REVENUE RECOVERY AND NON-TECHNICAL LOSSES

The analysis in section 10.2 assumes that all of the energy supplied to customers is accounted for in the customer revenue. Non-technical losses (including theft) may be significant [Cespedes et al, 1983; Ferreyra and Paoletich, 2001 and Mupwaya, 2003].

Non-technical losses effectively reduce the price paid by customers, and can be factored into equations 10.1.4 and 10.1.5 as follows:

$$CLLE \approx ULT_{ac} \cdot (1 - K_e) + K_e \cdot CT_{ac} \cdot RRR \quad 10.3.1$$

$$CLLD \approx ULT_{ad} \cdot (1 - K_d) + K_d \cdot CT_{ad} \cdot RRR \quad 10.3.2$$

**RRR** Revenue Recovery Rate [per-unit]

The Revenue Recovery Rate refers to the per-unit revenue that is recovered as compared to the ideal state where all revenue is recovered (zero non-technical losses).

The case study in section 10.2 is repeated for five levels of revenue recovery, and the results for the 35mm<sup>2</sup> ABC conductor are summarised in table 10.3.1. The load characteristic is the same as used in section 10.2. In reality the level of non-technical losses may change the load characteristic. For practical application, changes in load characteristic may need to be reflected in load models, but is not required for this illustrative case study. The errors in the proposed method (including the effects of revenue recovery) are similar to those in table 10.2.3 and have not been included.

35mm <sup>2</sup> ABC conductor	Revenue Recovery Rate (RRR)	Load voltage dependency				
		K = 0	K = 0.5	K = 1	K = 1.5	K = 2
Cost per kWh of weekday technical load loss energy, including the effect of the change in revenue [Rand/kWh]	100%	R 0.13 (R 0.31)	R 0.26 (R 0.36)	R 0.41 (R 0.41)	R 0.55 (R 0.46)	R 0.70 (R 0.51)
	75%	R 0.13 (R 0.31)	R 0.21 (R 0.31)	R 0.30 (R 0.30)	R 0.40 (R 0.30)	R 0.49 (R 0.30)
	50%	R 0.13 (R 0.31)	R 0.16 (R 0.26)	R 0.20 (R 0.20)	R 0.24 (R 0.15)	R 0.28 (R 0.10)
	25%	R 0.13 (R 0.31)	R 0.11 (R 0.21)	R 0.10 (R 0.10)	R 0.09 (R 0.00)	R 0.08 (-R 0.11)
	0%	R 0.13 (R 0.31)	R 0.06 (R 0.16)	R 0.00 (R 0.00)	-R 0.06 (-R 0.16)	-R 0.13 (-R 0.31)

Table 10.3.1: 35mm<sup>2</sup> ABC conductor case study summary results for different Revenue Recovery Rates. High and Low season WEPS results are provided with and without brackets respectively

The following can be observed from table 10.3.1:

- The Revenue Recovery Rate has a significant impact on the effective cost of load loss energy for loads that are not constant power.

- The effective load loss energy cost in networks with loads tending towards constant impedance and Revenue Recovery Rate <50% can result in a net cost saving. This arises as less energy is supplied to customers, thereby reducing the cost to the utility if the revenue is not being recovered by the utility. In extreme cases ( $K = 2$  and  $RRR = 0$ ) the effective load loss energy cost saving is the Utility Loss Tariff energy charge.

For customers with low revenue recovery the consumption of energy is likely to be price inelastic and  $K_e$  will be largely determined by the appliance characteristics ( $K_e$  will tend towards  $K_d$ ). It is hence probable that with low-income domestic consumers, the load energy voltage dependency increases with reduced revenue recovery. The implications for network planning and design are significant as revenue recovery levels may have a large impact on the effective cost of load losses (over and above load characteristics such as load shape and magnitude), and thereby influence capital investment decisions including optimal conductor sizes (raised in section 3.2). Networks with increased load losses could result in a net cost saving (as compared to networks with lower load losses) if consumers are voltage sensitive and revenue recovery is low. It should also be noted that consumer energy consumption and hence non-technical losses vary with conductor size for loads that are not constant power. This is an important finding as non-technical losses can not be considered a common cost for conductor size optimisation (raised in section 2.2).

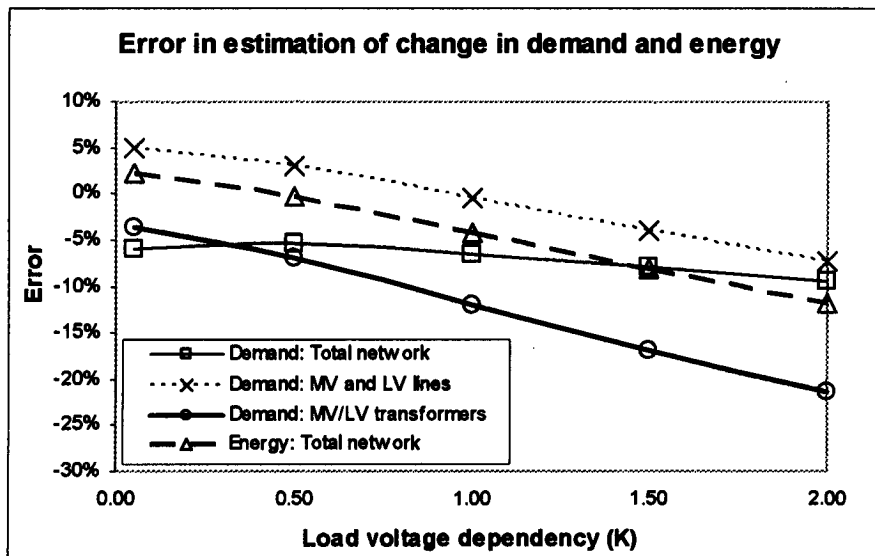
It is interesting to note that no-load losses are unity load factor, constant impedance ( $K=2$ ) loads with no revenue recovery ( $RRR=0$ ). The effective cost of load loss energy in branches supplying predominately no-load loss energy may be negative thereby resulting in a cost saving.

#### 10.4 TESTING ON A PRACTICAL SOUTH AFRICAN RURAL DOMESTIC ELECTRIFICATION NETWORK

The error in the approximation of change in consumer energy/demand based on load loss and load voltage dependency (equation 10.1.3) is dependent on the load power factor, network reactance and non-linearity in the load voltage dependency. The accuracy of the proposed method and its sensitivity to these dependencies was tested on the sample rural domestic electrification network described in section 9.2. As per section 10.2, a constant current load model was used with the proposed method.

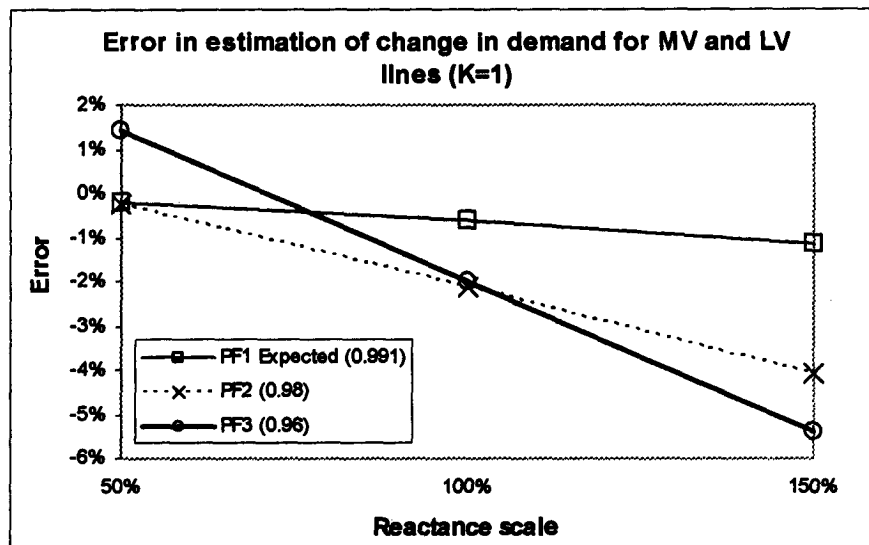
The errors in the estimation of the change in consumer energy and demand (based on load loss and load voltage dependency as per equation 10.1.3) are given in figure 10.4.1 for the expected power factor and network reactance. The errors are large when applied to MV/LV transformers as their impedance is largely reactive. MV and LV lines have lower X/R ratios as compared to transformers, and the errors are acceptable for practical analysis purposes. Referring to section 7.6.2, it can be confirmed that for the evaluation of line load losses and voltage drop the change in consumer energy consumption and demand can be estimated based on the load loss and load voltage dependency.

Figure 10.4.1: Error in prediction of change in consumer energy consumption and demand (expected reactance and power factor)



The sensitivity of the error for MV and LV lines is provided in figure 10.4.2 for varying load power factor and network reactance (constant current load model). The error is acceptable for moderate changes in power factor and reactance.

Figure 10.4.2: Sensitivity of the error in the prediction of the change in consumer demand for MV and LV lines (constant current load)



## 10.5 CONCLUSIONS

An approximate relationship between load loss, load voltage dependency and change in consumer energy/demand has been used to derive a composite load loss energy and demand cost that include the missed opportunity cost due to changes in consumer energy consumption and demand as a result of voltage drop and load voltage dependency. The following conclusions can be drawn:

- The impact of load losses on utility bulk energy purchases varies with load voltage dependency in passive distribution networks. Load losses do not necessarily increase utility bulk energy purchases. Increased load loss in networks supplying constant impedance loads reduces total system loading.
- Conductor voltage drop affects consumer energy consumption and demand (and hence utility revenue) for loads that are not constant power.
- In passive distribution networks, the omission of voltage drop and load voltage dependency (variations in consumer energy consumption and demand) can result in large errors in technical load loss costing for network planning and design if loads do not behave with a constant power characteristic (raised in section 5.3.2).
- Consumer energy consumption and demand and hence utility bulk energy purchase costs and revenue are significantly affected by conductor size (raised in sections 2.2 and 3.2). The effects of conductor size on consumer energy consumption and demand and

utility bulk energy purchase costs and revenue need to be included in conductor size optimisation for loads that are not constant power.

- The method incorporating voltage drop and load voltage dependency in the effective cost of load losses utilises constant current load models for load loss calculations and is hence simple to apply in practical applications.
- The method was tested on a case network and a practical South African rural domestic electrification network. The method is sufficiently accurate for MV and LV network planning and design in networks supplying predominantly domestic consumers, but can only be applied to lines. Errors are unacceptably large for distribution transformer loss assessment due to their predominately reactive impedance.
- The effective technical load loss cost is sensitive to the load voltage dependency. Appropriate values for  $K_e$  and  $K_d$  need to be established for different load types in South Africa.
- The effective technical load loss cost is sensitive to the relative difference between the Utility Loss Tariff and Customer Tariff, and the rate of revenue recovery. Non-technical losses may have a significant impact on the effective cost of load losses. Non-technical losses should be included in conductor size optimisation (raised in section 3.2).

The method applies to both energy and demand active load loss costs, however  $K_e$  and  $K_d$  may vary significantly from one another for the same customer class e.g. very low income domestic consumers (consumption severely constrained by affordability) may behave over short time periods as constant impedance loads ( $K_d = 2$ ), but their monthly energy consumption may not be affected by voltage variation ( $K_e = 0$ ).

The method does not apply to reactive load loss costing.

## 10.6 LOOKING FORWARD

The effective cost of load losses (incorporating voltage drop and load voltage dependency) needs to be incorporated into a statistical time-of-use load loss calculation technique as outlined in chapter 7 such that the conductor lifetime costs of load losses and voltage drop can be included in a conductor size optimisation method.

# **11. STATISTICAL TIME-OF-USE LOSS CALCULATION, LOSS COSTING AND CONDUCTOR SIZE OPTIMISATION**

In this chapter a statistically based time-of-use load loss calculation and costing method is developed for radial distribution networks as per the requirements documented in chapters 5 and 7. Lifetime active and reactive energy losses, demand losses and loss costs are calculated and compared with the results of Monte Carlo simulation using South African domestic load research data. The results of deterministic techniques are also compared with the Monte Carlo simulation results.

The loss calculation and costing method is used to optimise conductor selection where the objective function is the minimisation of the sum of the lifetime conductor capital, technical loss and voltage drop costs (changes in utility bulk energy purchases and utility revenue), within the constraints of conductor thermal ratings.

## **11.1 LOAD LOSS ENERGY CALCULATION AND COSTING**

### **11.1.1 General**

Components of the load loss energy calculation and costing documented in this section are published by Carter-Brown and Gaunt [2005c].

### 11.1.2 Introduction to the load loss calculation load model

The average load loss active power in a phase or neutral conductor is given by [Heunis, 2000]:

$$Avg\ Loss = R \cdot (\mu_T^2 + \sigma_T^2) \quad 11.1.2.1$$

Avg Loss	Average load loss active power [W]
$\mu_T$	Conductor current mean [amps]
$\sigma_T$	Conductor current standard deviation [amps]

The expected value of  $\mu_T$  and  $\sigma_T^2$  can be calculated for a group of N consumers using the following rules governing random variables [Heunis, 2000]:

$$\mu_T = \sum_{i=1}^N \mu_i \quad 11.1.2.2$$

$$\sigma_T^2 = \sum_{i=1}^N \sigma_i^2 + \sum_{j=1}^N \sum_{\substack{k=1 \\ j \neq k}}^N \sigma_j \cdot \sigma_k \cdot \rho_{jk} \quad 11.1.2.3$$

$\mu_i$	Average value of the load current of consumer i [amps]
$\sigma_i^2$	Variance of the load current of consumer i [amps <sup>2</sup> ]
$\sigma_j, \sigma_k$	Standard deviation of the load current of consumers j and k [amps]
$\rho_{jk}$	Correlation between the load currents of consumers j and k

If a load is scaled, the following rules governing scaled random variables must be met [Heunis, 2000]:

$$\mu_T = \sum_{i=1}^N SF_i \cdot \mu_i \quad 11.1.2.4$$

$$\sigma_T^2 = \sum_{i=1}^N SF_i^2 \cdot \sigma_i^2 + \sum_{j=1}^N \sum_{\substack{k=1 \\ j \neq k}}^N SF_j \cdot SF_k \cdot \sigma_j \cdot \sigma_k \cdot \rho_{jk} \quad 11.1.2.5$$

$SF_i, SF_j$	Scaling factor of consumers i and j [per-unit]
--------------	------------------------------------------------

The expected value of  $\mu_T$  and  $\sigma_T^2$  for a group of  $N$  consumers in the same load class is given by [Herman and Heunis, 2002]:

$$\mu_T = N \cdot E[\mu] \quad 11.1.2.6$$

$$\sigma_T^2 = N \cdot (V[\mu] + E[\sigma^2]) + N \cdot (N - 1) \cdot E[\rho] \cdot E[\sigma]^2 \quad 11.1.2.7$$

$E[\mu]$	Average of the load current signal means [amps]
$V[\mu]$	Variance of the mean values of the load current signal [amps <sup>2</sup> ]
$E[\sigma]$	Average of the load current signal standard deviations [amps]
$E[\sigma^2]$	Average of the load current signal variances [amps <sup>2</sup> ]
$E[\rho]$	Average of the correlation of load current signals [unitless]

Note: This is based on a constant current load assumption.

If a group of consumers in the same class is scaled by a factor  $SF$ :

$$\mu_T = N \cdot SF \cdot E[\mu] \quad 11.1.2.8$$

$$\sigma_T^2 = N \cdot SF^2 \cdot (V[\mu] + E[\sigma^2]) + N \cdot (N - 1) \cdot E[\rho] \cdot SF^2 \cdot E[\sigma]^2 \quad 11.1.2.9$$

$SF$             Scaling factor [per-unit]

The above equations apply to a linear combination of currents, where the current of each consumer is in phase with all other consumer currents. In a phase or neutral conductor the current of each consumer is a phasor, the angle of which can vary due to:

- the consumer load power factor, and
- the fixed angle associated with the network technology and transformations. For example the current in the neutral conductor of a three phase four wire branch can have contributions from up to three phase angles; 0°, 120° and 240°.

The phase angle of the load currents can be factored into the calculations as follows such that the calculations can be applied to a range of unbalanced network technologies and customer connection arrangements:

- The mean of the sum of load currents is calculated via vectorial addition of the mean load currents.
- The phase angle between load currents changes the effective correlation of the load currents. The variance of the sum of load currents is calculated by multiplying the correlation coefficient with the cosine of the difference in angle between load currents.

Practical distribution networks consist of a mixture of customer classes, within which there are groupings of consumers with the same load magnitude (scaling factor) and phase angle (they are supplied by the same phase and have the same power factor). In order to reduce the number of calculations required to calculate the variance, consumers with the same characteristics (load class, magnitude and angle) are grouped into Load Bins, whereby:

$$\mu_T = \left| \sum_{l=1}^{LB} (SF_l \cdot N_l \cdot \overline{E[\mu_l]}_{Angle(A_l)}) \right| \quad 11.1.2.10$$

$$\sigma_T^2 = \sum_{l=1}^{LB} \left( \left( V[\mu_l] + E[\sigma_l^2] \right) \cdot N_l \cdot SF_l^2 + E[\rho_l] \cdot E[\sigma_l]^2 \cdot N_l \cdot (N_l - 1) \cdot SF_l^2 \right) + \sum_{j=1}^{LB} \sum_{\substack{k=1 \\ j \neq k}}^{LB} \left( E[\rho_{jk}] \cdot E[\sigma_j] \cdot E[\sigma_k] \cdot N_j \cdot N_k \cdot SF_j \cdot SF_k \cdot \cos(A_j - A_k) \right) \quad 11.1.2.11$$

LB	Number of Load Bins
$E[\mu_l]$	Average of the Load Bin l current signal means [amps]
$V[\mu_l]$	Variance of the Load Bin l mean values of the current signal [amps <sup>2</sup> ]
$E[\sigma_l^2]$	Average of the Load Bin l current signal variances [amps <sup>2</sup> ]
$E[\sigma_l], E[\sigma_j], E[\sigma_k]$	Average of the Load Bin l, j and k current signal standard deviations respectively [amps]
$E[\rho_l]$	Average of the correlation of Load Bin l current signals [unitless]
$E[\rho_{jk}]$	Average of the correlation of current signals between Load Bins j and k [unitless]
$A_l, A_j, A_k$	Phase angle of Load Bin l, j and k currents respectively [degrees]
$N_l, N_j, N_k$	Number of consumers in Load Bin l, j and k respectively

$SF_i, SF_j, SF_k$       Scaling factor of Load Bin i, j and k respectively

By grouping loads into bins the number of calculations required to calculate the variance is significantly reduced. If each consumer were treated separately the number of calculations in a branch supplying 1000 consumers would be  $1000 * (1000 - 1) = 999000$ . In a practical network 1000 consumers could for example be grouped into 20 Load Bins. The number of calculations is  $20 * (20 - 1) = 380$ , a reduction of 99.96%. The method is hence appropriate for application in both MV and LV networks.

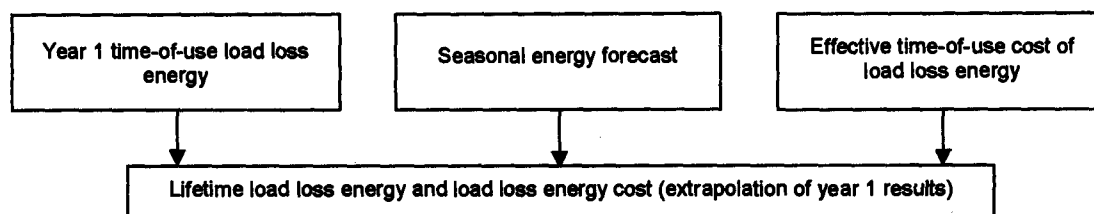
### 11.1.3 Overview of load loss energy calculation and costing

The load loss energy calculation and costing is detailed in appendix E. The calculations consist of a number of sub-components as illustrated in figure 11.1.3.1. The method has the following main features:

- Consumers are modelled as Fixed Loads and variable loads. Each variable load is associated with a Load Group (customers within a Load Group are homogeneous i.e. of the same class).
- Fixed Loads are constant (have unity Load Factor and zero load growth).
- Load Groups are described by daily load profiles for different day types and seasons of the year. The time interval, number of day types, number of seasons in a year and number of days of each day type in each season are user defined. The load profile structure is fixed for all future years.
- The load shape of each Load Group is assumed to remain constant in future years. Changes in consumer energy consumption and demand in future years are described by separate per-unit energy and demand load forecasts for each Load Group. Different energy and demand forecasts are used to account for small changes in Load Factor in future years.
- The load loss energy and load loss energy cost calculations are performed separately for each phase and neutral conductor in each branch of the network.
- The active and reactive load loss energy and load loss energy cost are normalised relative to conductor resistance and reactance [ $kWh/\Omega$  and  $Rand/\Omega$ ] (constant current load models are used for load loss calculations and changes in conductor impedance do not affect conductor currents). The load loss energy and load loss energy cost associated with a particular conductor phase/neutral conductor is obtained by multiplying the normalised load loss energy and load loss energy cost with the phase/neutral resistance (active energy and cost) and reactance (reactive energy and cost).

- The average load loss energy in each time interval, day type and season is calculated in year 1 using the load model described in section 11.1.2, and is based on a constant current load model. The accuracy of these calculations needs to be tested.
- Load Groups can have different load shapes and different load forecasts. The load characteristics (shape and magnitude) supplied by each conductor can change significantly in future years. The average load loss energy in each time interval, day type and season is not recalculated in each future year as this would be calculation intensive. For each phase/neutral conductor an annual energy load forecast is calculated for each season taking into consideration the phasing of the load currents and the growth rates of the different Load Groups. The accuracy of this approach needs to be tested.
- The year 1 load loss energy and load loss energy costs are combined with the seasonal energy forecasts to obtain the lifetime load loss energy and load loss energy cost. The lifetime evaluation period is specified by the user.
- A forecast limit can be applied such that the load forecast used in the loss calculations is capped in a user specified year. As a result scenarios can be modelled where the additional load beyond a certain year is supplied by a network upgrade, and not by the original network.
- The Utility Loss Tariff is time-of-use and provides the active energy charge in each time interval, day type and season, and has a per-unit annual forecast. In future years the structure of the tariff and relative cost differences between time intervals remains constant. Customer Tariffs have a fixed energy rate (are not time-of-use) as is presently the case with South African domestic customer tariffs [Eskom, 2005b], and have per-unit annual forecasts. The method can be enhanced to cater for time-of-use Customer Tariffs. Note that the Utility Loss Tariff and Customer Tariff forecasts can differ.
- The Utility Loss Tariff, Customer Tariffs and consumer energy voltage dependency are combined to calculate the effective cost of active load loss energy in each time interval, day type, season and year using the method described in chapter 10. As a result the missed opportunity cost due to changes in consumer energy consumption (as a result of the voltage drops over conductors and load voltage dependency) is included in the analysis.
- Reactive load loss energy costs are based on switched shunt capacitor lifetime costs.
- The network topology is constant for the entire evaluation period. The connection of additional customers in a future year can be accommodated via manipulation of the load forecast of the associated Load Group.
- The method supports the range of standard technologies used in Eskom Distribution in both MV and LV networks (tables 2.1.1 and 2.1.2).

Figure 11.1.3.1: Overview of load loss energy calculation and costing



### Year 1 time-of-use load loss energy

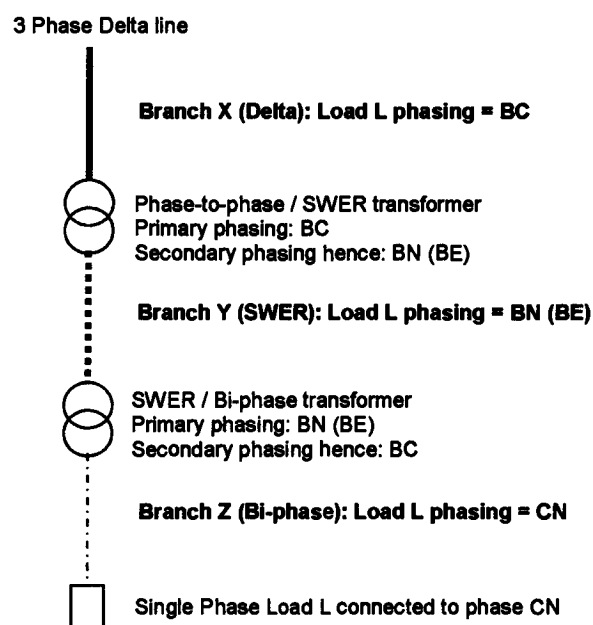
The load loss energy in each phase/neutral conductor in each time interval, day type and season in year 1 is calculated with the following key features and assumptions:

- Fixed and variable loads are modelled as constant current loads, taking into consideration the load power factor, load variance and correlation.
- Loads from different Load Groups are combined assuming zero correlation. This assumption significantly simplifies the calculations. The accuracy of this assumption needs to be tested.
- Balanced three phase and bi-phase loads are modelled as corresponding single phase loads of equal magnitude (the balanced three and bi-phase loads are distributed evenly over the available phases).
- All consumers of a particular Load Group have the same load characteristics i.e. are homogeneous and are connected at the same time.
- Fixed loads are described by their connection phasing, apparent power, power factor, scaling factor and energy and demand voltage dependency.
- Variable loads in the form of Load Groups are described by consumer numbers, connection phasing and  $E[\mu]$ ,  $V[\mu]$ ,  $E[\sigma]$ ,  $E[\sigma^2]$ , and  $E[\rho]$  in each time interval, day type and season. Load seasonal changes are described by variations in the load shape and/or load magnitude. This approach is flexible and facilitates detailed load profile modelling should seasonal load profile data be available for different Load Groups.
- The load power factor is described by a mean power factor in each time interval, day type and season. The variance of the power factor is not included in the calculations as the variance is small and the additional complexity is not justified (see section 8.4).
- Load Groups are scaled via a scaling factor to cater for adjustments in load magnitude i.e. a load characteristic can be scaled to suit application in a specific study.
- Transformer no-load losses and shunt capacitors are modelled as Fixed Loads with appropriate power factors and energy voltage dependency (as defined by the user). The

effect of no-load losses and shunt capacitors on upstream currents and losses is included in the calculations. There are two implications 1) No-load losses and shunt capacitor currents impact the load loss energy in upstream branches, and 2) The impact of upstream impedance on no-load losses is accounted for in the cost of the load loss energy in the upstream branches (the effective cost of load loss energy in upstream branches is reduced by downstream no-load losses as lower voltages result in reduced no-load losses).

- The load loss calculations are based on a constant current load model. The effects of transformation ratios and DETS tap settings are included in the calculations. A load-flow is not performed in each time interval. Changes in auto-tapping transformer and voltage regulator tap positions and shunt capacitor switching are not accounted for.
- To improve accurately with switched capacitor banks and automatic tap changing, the method could be enhanced to include load-flow using the mean loading in each time interval. The load-flow results would be used to establish the status of switches, tap settings and load scaling factors in each time interval. The calculations would increase significantly as load-flow would be required and the number of Load Bins would increase (the number of Load Bins increases proportional to the number of different scaling factors). Given the calculation implications and relatively low sensitivity of the load loss to load voltage dependency (see section 9.5) the requirement to incorporate load-flow in the loss calculation has not been considered further.

Figure 11.1.3.2: Example load technology and phasing transformation



- The transformation of loads between network technologies and branches is incorporated into the calculations such that the load current magnitudes and angles in upstream branches are modelled. For example, referring to figure 11.1.3.2, a single phase load (L) connected to phase CN is seen as a phase to neutral (CN) current in branch Z, a phase to ground (BE) current in branch Y, and a phase-to-phase (BC) current in branch X. The nominal voltage of each branch and transformer ratios (including tap position) are accounted for.

### Seasonal energy forecast

The future year load loss energy in a phase/neutral conductor is dependent on load growth or decline. With loads exhibiting seasonal variations the seasonal loads supplied by a phase/neutral conductor may vary significantly. To improve accuracy with highly seasonal loads and mixtures of loads growing at different rates, a phase/neutral conductor annual apparent energy load forecast is calculated for each season of the year. In order to derive this annual forecast, the per-unit contribution of each Load Group to the seasonal apparent energy supplied by the phase/neutral conductor is calculated. As the contributions of the Load Groups are not necessarily in phase (e.g. neutral conductors), phase angles are considered in the calculation.

The pro-rata contributions of each Load Group energy forecast are summated (using the per-unit contribution of each Load Group) to obtain the phase/neutral conductor annual apparent energy forecast for each season of the year.

### Effective time-of-use cost of load loss energy

The effective load loss energy cost in each time interval, day type and season of each year is dependent of the Utility Loss Tariff, Customer Tariffs and load energy voltage dependency.

Different Fixed Loads and Load Groups have different Customer Tariffs and energy voltage dependencies. The effective cost of load loss energy in each time interval, day type, season and year is dependent on the contribution of each Fixed Load and Load Group to the load loss.

The per-unit contribution of each Fixed Load and Load Group to the apparent energy supplied by each phase/neutral conductor is calculated in each time interval, day type and season in year 1. Phase angles are taken into consideration in this calculation.

Auto-tap transformers and voltage regulators are assumed to regulate the downstream voltage such that voltage drops in upstream branches have negligible impact on the voltage variation at downstream loads. The presence of auto-tap transformers and voltage regulators between branches and loads is used to adjust the load voltage dependency as seen by the upstream branches (if there is an auto-tap transformer or regulator between an upstream branch and a load, then the load voltage dependency is zero for the costing of load loss energy in that upstream branch). As a result the method used to include missed opportunity costs due to voltage variation can also be applied to active networks with line voltage regulators and auto-tap transformers.

The per-unit contributions of each Load Group and Fixed Load are combined with the load voltage dependencies (as adjusted based on the presence of auto-tap transformers and regulators), Utility Loss Tariff and Customer Tariffs to calculate the effective cost of load loss energy in each time interval, day type, season and year in each phase/neutral conductor. Separate Utility Loss Tariff and Customer Tariff forecasts are supported whereby future generation/transmission charges and consumer tariffs can increase or decrease at different rates.

#### Lifetime load loss energy and load loss energy cost (extrapolation of year 1 results)

The lifetime load loss energy and load loss energy and voltage drop cost are calculated for each phase/neutral conductor with the following features and assumptions:

- The future year load loss energy is calculated using the load loss energy in year 1, the annual apparent energy forecast for each season and the number of days of each day type in each season. The change in future year load loss energy relative to year 1 is assumed to be proportional to the square of the per-unit change in apparent energy. This assumption is valid for constant current loads.
- The future year load loss energy cost is calculated by combining the future year load loss energy in each time interval, day type and season, number of days of each type in each season and the effective cost of load loss energy in each time interval, day type, season and year.
- The lifetime load loss energy cost is expressed as a Present Value by discounting future year costs using a user defined Net Discount Rate.
- A fixed reactive energy charge (not time-of-use) is used for the costing of load loss reactive energy.

- Reactive load loss energy costs are assumed to increase at the general inflation rate as they are based on switched shunt capacitor capital and maintenance costs.

#### 11.1.4 Load loss energy testing

##### Monte Carlo simulation

Monte Carlo simulation using Load Research data is considered the most appropriate method for the testing of load loss calculation methods applied to networks supplying stochastic loads [Heunis, 2000]. The Monte Carlo simulation method as applied to South African load research data is described by Heunis [2000] and is not repeated here.

The Monte Carlo simulation software developed by Heunis [2000] was enhanced by Dr Heunis based on a specification provided by this research, a summary of which is provided in appendix F. Dr Heunis was contracted to perform the enhancements due to his development of the original Monte Carlo simulation software, thereby avoiding considerable additional development time. The Monte Carlo simulation and load parameter extraction software was enhanced as follows:

- Load loss energy and demand calculations are performed using load research data with a 5 minute time interval. 1 hour results are extracted from the 5 minute interval results.
- The average 1 hourly load loss energy values are multiplied by time-of-use energy charges to obtain the load loss energy costs for different times of day, day types (weekdays, Saturdays and Sundays) and months.
- The average 1 hourly load loss demands (in a user specified time period and day type) are multiplied by a monthly differentiated demand charge to obtain the load loss demand cost for each month.
- Up to three customer Load Groups can be mixed in the same network.
- Delta, star and bi-phase network technologies are supported (single phase networks can be simulated using the star or bi-phase network models).
- The load parameter extraction for a community provides time-of-use values for different hours in the day, day types and months of year.

For the purposes of testing, 1000 iterations provides acceptable accuracy [Heunis, 2000] and 1000 iterations have been used for all Monte Carlo simulations reported in this research.

### LV networks with homogeneous consumers

The load loss energy and load loss energy costing method was tested on radial LV feeders with the following characteristics and evaluation parameters:

- Tests were performed using benchmark networks prescribed for testing of the Herman Beta voltage drop calculation [NRS 034-1, 1999]. The test networks exhibit the characteristics of practical South African LV networks and include mixtures of three phase, bi-phase and single phase technologies, unbalanced customer connections, tapered conductor sizes and different phase and neutral conductor resistances.
- The range of consumer Load Groups listed in table 11.1.4.1 represents the diverse spread of South African domestic consumers.
- The customers on a feeder are limited to the same Load Group (homogeneous customers) and the analysis is confined to the load data in the year of data collection (zero load growth).
- The Eskom 2005 WEPS [Eskom, 2005a] was used for the time-of-use Utility Loss Tariff energy charges. For the purposes of testing the time-of-use load loss calculations, the Load loss energy costs are only based on the Utility Loss Tariff i.e. no Customer Tariff, and changes in revenue due to voltage variations are ignored.
- Due to limitations in the Monte Carlo simulation software network modelling capabilities, only the load loss in the “backbone” between the source and most distant node were calculated. This is sufficient for testing (comparative) purposes.
- The Monte Carlo simulation and proposed methods both use a constant current load model for the calculation of load losses.

Referring to figure 11.1.4.1, the 70mm<sup>2</sup> conductor has a phase and neutral resistance of 0.443Ω/km and 0.6202Ω/km respectively [NRS 034-1, 1999]. The 35mm<sup>2</sup> conductor has an equal phase and neutral resistances of 0.868Ω/km [NRS 034-1, 1999].

The NRS 034-1 [1999] does not provide a benchmark delta network. The NRS034 Case 3 three phase star network has been modified to create a benchmark delta network as illustrated in figure 11.1.4.3.

Figure 11.1.4.1: Three phase star test network with single phase spurs: NRS034 Case 5 [NRS 034-1, 1999]. The notation x,y,z indicates the number of consumers connected to phases A, B and C respectively

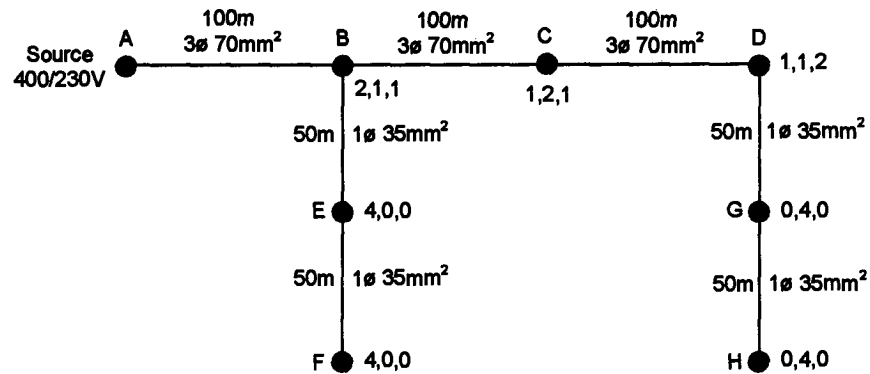


Figure 11.1.4.2: Bi-phase test network with single phase spurs: NRS034 Case 6 [NRS 034-1, 1999]. Same conductor impedances as for NRS034 Case 5. The notation x,y indicates the number of consumers connected to phases A and B respectively

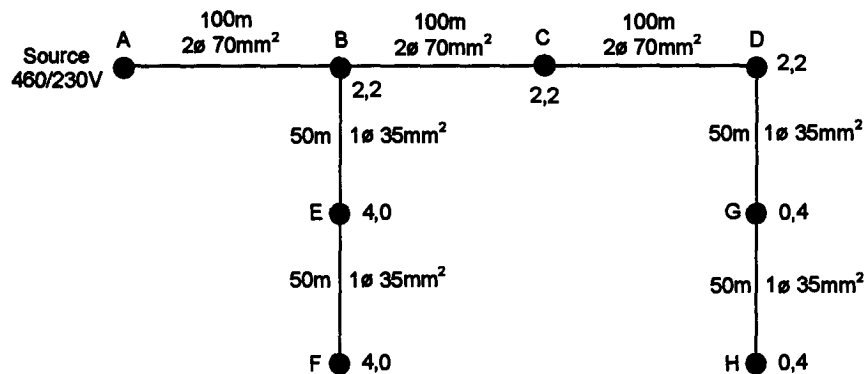
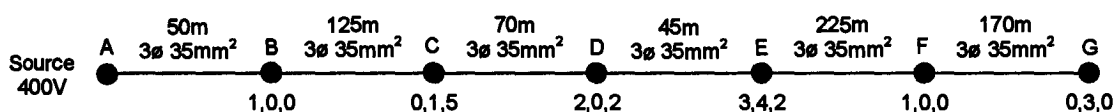


Figure 11.1.4.3: Three phase delta test network: Based on NRS034 Case 3 [NRS 034-1, 1999]. The phase conductor resistance is 0.868Ω/km (no neutral conductor). The notation x,y,z indicates the number of consumers connected to phases AB, BC and CA respectively



Load Group (community)	Monthly energy consumption [kWh]
1994 Cloetesville	762
1997 Claremont	1232
1997 Walmer	147
1998 Claremont	1184
1998 Umgaga	230
1998 Walmer	159
1999 Summerstrand	581
2000 Helderberg	943
2000 Orient	507
2001 Antioch	71
2001 Garagapola	128
2001 Tambo	78
2002 Antioch	71
2002 Gasese	116
2002 Mfazazane	183
2002 Moreietta	1722
2002 Welgemoed	1173

Table 11.1.4.1: Consumer load groups used in load loss calculation testing

Load Group (community)	NRS034 Case 5 (3⊕Star)		NRS034 Case 6 (2⊕Bi-Phase)		NRS034 Case 3 mod (3⊕Delta)	
	Energy [%]	Cost [%]	Energy [%]	Cost [%]	Energy [%]	Cost [%]
1994 Cloetesville	-0.02%	0.29%	0.23%	0.52%	0.31%	0.62%
1997 Claremont	0.02%	-0.07%	-0.34%	-0.49%	0.28%	0.16%
1997 Walmer	0.10%	-0.39%	0.48%	-0.02%	1.38%	0.69%
1998 Claremont	0.85%	0.82%	0.87%	0.84%	0.22%	0.35%
1998 Umgaga	1.58%	1.14%	1.69%	1.47%	1.00%	0.63%
1998 Walmer	1.84%	0.97%	0.55%	-0.43%	0.90%	-0.09%
1999 Summerstrand	0.49%	0.26%	0.73%	0.48%	-0.70%	-0.94%
2000 Helderberg	0.20%	0.11%	0.23%	0.15%	0.24%	0.05%
2000 Orient	1.10%	0.29%	1.46%	0.62%	-0.03%	-0.84%
2001 Antioch	1.08%	1.20%	1.37%	1.56%	0.48%	0.16%
2001 Garagapola	1.50%	1.34%	1.26%	1.19%	-0.08%	-0.29%
2001 Tambo	1.08%	0.80%	0.41%	0.12%	-0.33%	-0.53%
2002 Antioch	-0.01%	-0.06%	-0.49%	-0.52%	-0.32%	-0.28%
2002 Gasese	1.97%	1.63%	1.53%	1.18%	-0.50%	-0.79%
2002 Mfazazane	1.35%	0.81%	1.39%	0.81%	1.79%	1.25%
2002 Moreietta	0.58%	0.39%	0.58%	0.37%	1.22%	1.01%
2002 Welgemoed	0.31%	0.19%	0.11%	0.02%	1.30%	1.19%

Table 11.1.4.2: Error in calculated load loss energy and load loss energy cost relative to the Monte Carlo simulation

The errors in table 11.1.4.2 are small (<2% for the tested networks), within practical planning and design requirements, and can be largely attributed to variances in the Monte Carlo calculations using 1000 iterations.

The accuracy of the load model described in section 11.1.2 (for the calculation of the average load loss energy) has been demonstrated using a time-of-use load model with 1 hour time intervals. The testing thus far has been confined to a single load class and year (zero load growth).

LV network with mixed consumers and different growth rates

To test the mixing of Load Groups and the accuracy of the technique used to account for load growth, the load loss energy calculation and load loss energy costing was tested on radial LV feeders supplying a mixture of different consumer load classes growing at different rates. The same approach was used as in the previous testing of feeders supplying homogeneous customers, but with the following additional characteristics:

- The NRS034-1 LV feeders were modified to include mixed customer classes as per figures 11.1.4.4, 11.1.4.5 and 11.1.4.6.
- Each feeder supplies a mixture of three domestic Load Groups (L1, L2 and L3 in table 11.1.4.3 and figure 11.1.4.7).
- The evaluation period is June and July 2002 (the period of overlapping load data for the three Load Groups).
- There is no real price increase in the Eskom 2005 WEPS [Eskom, 2005a] charges in future years (the WEPS charges are assumed to escalate at the general inflation rate).
- A 10 year lifetime was used for the load loss energy and load loss energy cost calculations.
- A Net Discount Rate of 8% was used for the present value costing of future year losses.

Figure 11.1.4.4: NRS034 Case 5 [NRS 034-1, 1999] with mixed loads. L1, L2 and L3 refer to Load Groups L1, L2 and L3 respectively

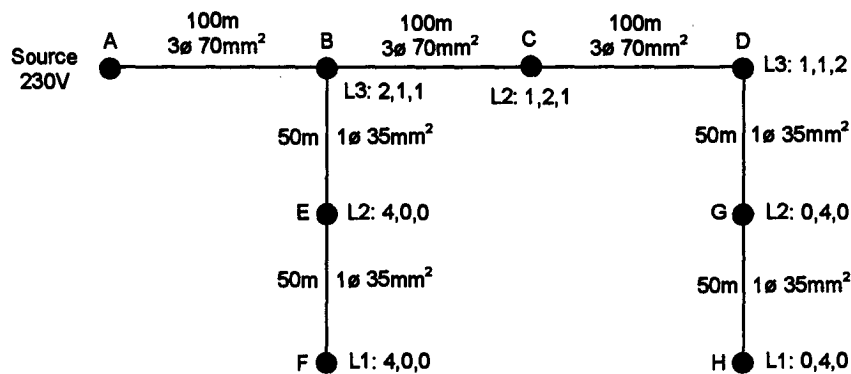


Figure 11.1.4.5: NRS034 Case 6 [NRS 034-1, 1999] with mixed loads

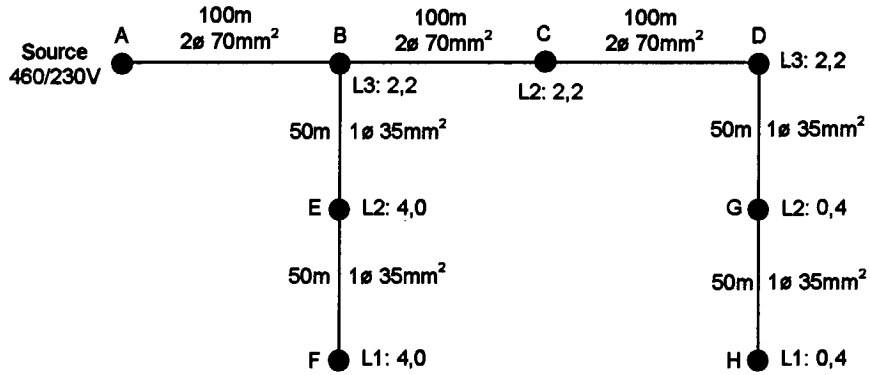
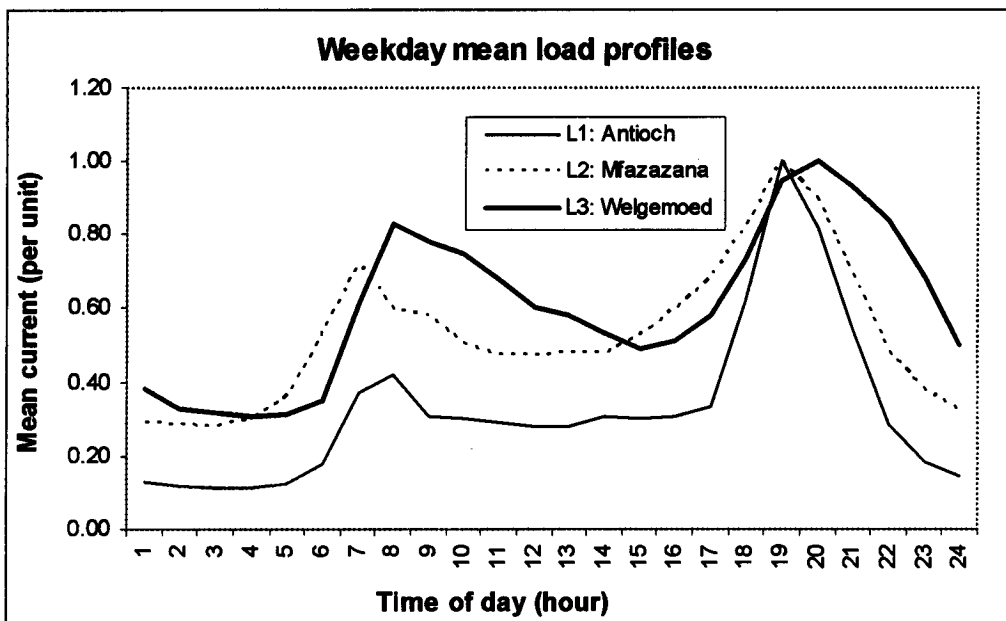


Figure 11.1.4.6: Modified (delta) NRS034 Case 3 [NRS 034-1, 1999] with mixed loads



Figure 11.1.4.7: Per-unitised weekday mean current profiles (June and July 2002) for each of the three domestic Load Groups used for testing



Load Group (community)	Average monthly consumption [kWh]	Growth rate [% per annum]
L1: 2002 Antioch	71	10 %
L2: 2002 Mfazazana	183	5 %
L3: 2002 Weigemoed	1173	3 %

Table 11.1.4.3: Summary of load data used to test the proposed method with mixed Load Groups

In sections 5.2.2 and 5.2.11 it was established that the Loss Load Factor and average profile load-flow methods need to be tested and compared with the method developed by this research. Table 11.1.4.4 compares the results of the Monte Carlo simulation and the calculated values of load loss energy and load loss energy cost for the sample networks and loads over the 10 year evaluation period. Three methods were tested:

- 1) Loss Load Factor (LLF) with load-flow at peak loading as used by Nickel and Braunstein [1981], Cespedes et al [1983], Flinn et al [1983], Baylor and Gustafson [1989], Grainger and Kendrew [1989], Bacelar [1995], IEC 287-3-2 [1995], Willis [1997], NRS 034-1 [1999], Sellick [1999], Davidson et al [2002], Mandal and Pahwa [2002] and Falaghi et al [2005]: The load loss at peak loading in year 1 is calculated using load-flow (constant current load model), and multiplied by the LLF (calculated using the Load Factor of the combined loads and an X of 0.08 as per equation 5.2.2.3) and hours in year 1 to obtain the load loss energy in year 1. The load loss energy is multiplied by the year 1 average WEPS energy charge to obtain the year 1 load loss energy cost. A feeder load forecast is calculated by combining the Load Group load forecasts with the pro-rata energy consumption of each Load Group. The combined load forecast is used to calculate the load loss energy in future years (future year losses are assumed to increase with the square of the per-unit load forecast). Future year costs are discounted to present year (year 1) values.
- 2) Average profile load-flow as used by Chen et al [1994] and Oliveira et al [2001]: The load loss energy in each 1 hour time interval for each weekday, Saturday and Sunday in each month in year 1 is calculated via load-flow (constant current load model) using the mean load profiles (hours/day types/months) for each Load Group. The year 1 load loss energy in each 1 hour time period is multiplied by the respective year 1 WEPS energy charge in each time interval to obtain the year 1 load loss energy cost. The feeder load forecast, future year load loss energy and future year load loss energy costs are calculated in the same manner as method 1, and costs are discounted to present year (year 1) values.

3) The proposed method: As described in this research.

Network	Method	Loss energy [kWh]	Loss energy error [%]	Loss energy cost [Rand]	Loss energy cost error [%]
NRS 034 Case 5 (star and single phase)	Monte Carlo simulation	5931	N/A	R 902	N/A
	1: LLF with load-flow at peak	3485	-41.24%	R 400	-55.70%
	2: Average profile load-flow	3668	-38.15%	R 581	-35.62%
	3: Proposed method	6017	1.45%	R 907	0.55%
NRS 034 Case 6 (bi-phase and single phase)	Monte Carlo simulation	7341	N/A	R 1126	N/A
	1: LLF with load-flow at peak	4846	-33.98%	R 556	-50.66%
	2: Average profile load-flow	5089	-30.67%	R 806	-28.40%
	3: Proposed method	7536	2.66%	R 1143	1.53%
NRS 034 Modified Case 3 (delta)	Monte Carlo simulation	7526	N/A	R 1172	N/A
	1: LLF with load-flow at peak	5288	-29.74%	R 601	-48.74%
	2: Average profile load-flow	6430	-14.57%	R 1009	-13.90%
	3: Proposed method	7537	0.14%	R 1168	-0.34%

Table 11.1.4.4: Mixed load 10 year load loss energy evaluation. Errors are differences relative to the Monte Carlo simulation

The differences between the Monte Carlo simulation, Loss Load Factor and average profile load-flow methods are large, and indicate that these methods are not suitable for energy loss calculation with stochastic loads such as in LV networks supplying domestic consumers. The average profile load-flow method improves load loss energy calculation and costing as compared to the LLF method, but errors are still large as the variance of the load within time intervals is not described.

The errors in the proposed method are small (<2.7% for the tested networks) and within practical planning and design requirements. The method used to mix load classes and account for different growth rates gives acceptably accurate lifetime load loss energy and load loss energy costs. Correlation between different Load Groups within 1 hour time intervals can be ignored (raised in section 7.5.2). A composite load forecast (raised in section 7.5.2) can be used to combine loads with different load shapes.

Impact of load voltage dependency and revenue recovery rate

The accuracy of the proposed method load loss energy calculations has been demonstrated. The errors in the Loss Load Factor and average profile load-flow methods increase further if the affect of load voltage dependency and voltage drop is included in the effective cost of load loss energy (see chapter 10).

The calculations for the mixed load NRS034 Case 5 were repeated for a range of load energy voltage dependencies and revenue recovery rates. The Customer Tariff energy charge is 40.68c/kWh (Eskom 2005 Homelight 1 tariff).

Load energy voltage dependency (K <sub>v</sub> )	Revenue Recovery Rate (RRR)				
	60%	70%	80%	90%	100%
0.0	R 906	R 906	R 906	R 906	R 906
0.5	R 958	R 1043	R 1127	R 1211	R 1295
1.0	R 1010	R 1179	R 1347	R 1515	R 1684
1.5	R 1062	R 1315	R 1567	R 1820	R 2073
2.0	R 1114	R 1451	R 1788	R 2124	R 2461

Table 11.1.4.5: NRS 034 Case 5 (mixed load over 10 years) effective load loss energy cost for variations in load voltage dependency and revenue recovery rate as calculated using the proposed method

Referring to the results in table 11.1.4.5, the effective cost of load loss energy (incorporating variations in consumer energy consumption due to conductor voltage drop and load voltage dependency) increases with increasing load voltage dependency and revenue recovery rate. The change in effective load loss energy cost is very significant for changes in revenue recovery rate and load voltage dependency (raised in section 3.2).

Referring to section 10.4, the approximation used in the proposed method to account for changes in consumer energy consumption due to conductor voltage drop results in a maximum error <7.5% for typical South African rural domestic electrification networks. The results in table 11.1.4.5 are expected to have a maximum error of less than 8% if the errors in the effective load loss energy cost calculation are included. Comparison of the load loss energy costs for the LLF, average profile load-flow and proposed method results (table 11.1.4.5) provides an indicative error for these methods.

Load energy voltage dependency (K <sub>v</sub> )	Revenue Recovery Rate (RRR)				
	60%	70%	80%	90%	100%
0.0	-55.94%	-55.94%	-55.94%	-55.94%	-55.94%
0.5	-58.33%	-61.69%	-64.55%	-67.02%	-69.16%
1.0	-60.46%	-66.11%	-70.35%	-73.64%	-76.28%
1.5	-62.39%	-69.62%	-74.51%	-78.05%	-80.73%
2.0	-64.14%	-72.47%	-77.65%	-81.20%	-83.77%

Table 11.1.4.6: NRS 034 Case 5 differences in load loss energy cost for the Loss Load Factor method relative to the proposed method

Load energy voltage dependency ( $K_v$ )	Revenue Recovery Rate (RRR)				
	60%	70%	80%	90%	100%
0.0	-35.97%	-35.97%	-35.97%	-35.97%	-35.97%
0.5	-39.43%	-44.32%	-48.48%	-52.06%	-55.18%
1.0	-42.54%	-50.75%	-56.90%	-61.69%	-65.52%
1.5	-45.34%	-55.84%	-62.96%	-68.10%	-71.99%
2.0	-47.88%	-59.98%	-67.52%	-72.67%	-76.41%

Table 11.1.4.7: NRS 034 Case 5 differences in load loss energy cost for the average profile load-flow method relative to the proposed method

The results in tables 11.1.4.6 and 11.1.4.7 show that the indicative errors in the Loss Load Factor and average profile load-flow methods increase significantly for loads that are not constant power. Assuming 100% revenue recovery and a constant current load ( $K_v=1$ ) the load loss energy costs for the Loss Load Factor and average profile load-flow methods account for less than 24% and 35% of the effective load loss energy costs respectively.

#### Mixed consumers with different load power factors

The Monte Carlo simulation and proposed method calculations were repeated on the mixed customer LV feeders assuming a power factor of 1, 0.95 and 0.90 for Antioch, Mfazazana and Welgemoed respectively to test the accuracy when mixing loads with different power factors. The power factors are not reflective of actual power factors for these domestic loads, but are extreme values to test the method.

Network	Result	Loss energy [kWh]	Loss energy error [%]	Loss energy cost [Rand]	Loss energy cost error [%]
NRS 034 Case 5 (star and single phase)	Monte Carlo simulation	5853	N/A	R 889	N/A
	Proposed method	5995	2.43%	R 904	1.66%
NRS 034 Case 6 (bi-phase and single phase)	Monte Carlo simulation	7268	N/A	R 1114	N/A
	Proposed method	7457	2.60%	R 1131	1.50%
NRS 034 Modified Case 3 (delta)	Monte Carlo simulation	7433	N/A	R 1157	N/A
	Proposed method	7440	0.09%	R 1153	-0.35%

Table 11.1.4.8: Mixed load 10 year load loss energy evaluation with mixed power factors. Errors are differences relative to the Monte Carlo simulation

The errors in the calculation of the lifetime load loss energy and load loss energy cost are less than 2.6%. It can be concluded that the average load power factor in each time interval and the mixing of loads with different power factors is accurately accounted for in the calculations.

In section 5.2.10 the need to quantify the impact of load power factor on load losses was identified. The Monte Carlo simulation results for the mixed load networks are compared in table 11.1.4.9, for the unity power factor (table 11.1.4.4) and mixed power factor (table 11.1.4.8) test cases.

Network	Change in load loss energy [%]	Change in load loss energy cost [%]
NRS 034 Case 5 (star and single phase)	-1.32%	-1.41%
NRS 034 Case 6 (bi-phase and single phase)	-0.99%	-1.07%
NRS 034 Modified Case 3 (delta)	-1.24%	-1.33%

Table 11.1.4.9: Change in load loss energy due to the consideration of load power factors

Referring to table 11.1.4.9, the change in load loss energy and load loss energy cost due to load power factor is less than 1.5%. The results indicate that in the sample networks tested the consideration of load power factor is not an important requirement for load loss assessment (assuming a constant current load model). The results may vary for different load mixes and load power factors.

Note that this finding is based on the assumption that the Load Group mean apparent power in each time interval does not vary with power factor. Errors may be large if apparent power load profiles are based on active power (not apparent power) measurements.

#### Non-domestic consumers

Limited South African non-domestic load research data constrains the testing of the method with mixtures of domestic and non-domestic loads. The method is expected to provide accurate results with non-domestic loads as domestic consumers are already highly stochastic, and the lower correlation between domestic and non-domestic consumers will further reduce errors when mixing Load Groups. The method incorporates power factor modelling, which may be important with non-domestic loads.

#### MV networks

As a consequence of the central limit theorem, the variance of the load relative to the mean decreases with increasing customer numbers. The proposed method accuracy should increase with increasing customer numbers. The accuracy of the proposed method when applied to MV networks is expected to be as good as or better than for LV networks. The accuracy in LV networks has been demonstrated.

The number of consumers monitored at each South African Domestic Load Research site is typically less than 50 [Dekenah, 2003]. In South Africa the number of domestic consumers supplied by a MV network is typically greater than 500. MV network Monte Carlo simulation can only be performed with replacement, and the variance of the load (and hence load loss) will be overstated.

The simulated and calculated load loss energy for three communities were compared for the generic South African rural domestic electrification MV network described in chapter 13. The results are summarised in table 11.1.4.10.

Load Group	Energy [%]	Cost [%]
2002 Antioch	-6.45%	-5.26%
2002 Mfazazana	-3.33%	-2.95%
2002 Welgemoed	-0.76%	-0.54%

Table 11.1.4.10: Difference between calculated and Monte Carlo simulated load loss energy and load loss energy cost (generic South African rural domestic electrification MV network supplying 2700 consumers)

Referring to table 11.1.4.10, the differences in the load loss energy and load loss energy cost for the generic MV network are less than -6.45%. The proposed method appears to understate the load loss energy and the cost thereof.

To test the possible error range due to replacement in the Monte Carlo simulation, load loss energy simulations were performed in a single branch/node network. The number of customers supplied by the branch is the maximum number of consumers ( $N_r$ ) before simulation with replacement is required. The simulations were performed with and without consumer replacement. The differences are summarised in table 11.1.4.11.

Load Group	$N_r$	Energy [%]	Cost [%]
2002 Antioch	52	-7.96%	-6.72%
2002 Mfazazana	47	-6.16%	-5.46%
2002 Welgemoed	49	-2.04%	-1.95%

Table 11.1.4.11: Difference between Monte Carlo simulated load loss energy and cost with and without consumer replacement. Results are relative to simulation with replacement

The differences and trends in tables 11.1.4.10 and 11.1.4.11 are similar and indicate that the majority of the difference between the simulated and calculated values for the generic MV

network load loss energy and load loss energy cost can be attributed to the overstatement of the variance in the Monte Carlo simulation (with replacement).

It can be concluded that the method provides acceptable accuracy for MV network analysis.

## 11.2 LOAD LOSS DEMAND CALCULATION AND COSTING

### 11.2.1 Overview of load loss demand calculation and costing

The load loss demand calculation and load loss demand costing is detailed in appendix E. The method has the following main features:

- The same load model, network model and assumptions are used as for the load loss energy calculations. Calculations are performed for each phase/neutral conductor in each branch. The results are normalised relative to conductor resistance.
- The load loss demand is based on the average load loss at a user defined system peak time interval. The system peak time interval is the time interval at which the load supplied at the generation/transmission/distribution interface peaks. The time of system peak may not coincide with the time of phase/neutral conductor peak loading, and hence the system peak time interval is user defined.
- The Utility Loss Tariff demand charge differentiates between seasons of the year. South African domestic consumers do not pay a demand charge [Eskom, 2005b]. The effective load loss demand costs (incorporating the effect of voltage drop and load voltage dependency on consumer demand) are hence a function of the Utility Loss Tariff demand charge and the load demand voltage dependency (see equation 10.1.6). As the method is developed for South African domestic electrification networks, Customer Tariff demand charges have been excluded. The method can be enhanced to cater for Customer Tariff demand charges (see comments in appendix E, section E.4.2).
- The effective load loss demand charge is calculated for each season in each future year.
- The load loss demand is not recalculated in each future year. For each phase/neutral conductor an annual apparent demand load forecast is calculated for each season taking into consideration the phasing of the load currents and the growth rates of the different Load Groups.
- The load loss demands in each season in each future year are calculated using the year 1 load loss demands and seasonal apparent demand forecasts. Future year load loss demand costs are calculated using the effective load loss demand charge (for each season in each year) and discounted to a present value.

### Year 1 load loss demand

The load loss demand at the time of system peak is based on the average load loss for that time interval. The load loss demand for planning and design evaluations is hence the average load loss demand during the system peak time interval. The actual load loss demand during system peak may differ from the average due to the stochastic nature of the load. The load loss demand will be under and over stated if the load (supplied by the phase/neutral conductor being studied) is positively correlated or negatively correlated respectively to the system load. As little may be known about the total system load (only its likely peak loading time and day type), the use of the average load loss demand is considered appropriate for practical planning and design.

The system peak time and day type are user defined and fixed for all seasons. The method can be enhanced such that the system peak time and day type could be specified separately for each season of the year.

### Seasonal apparent demand forecast

For each phase/neutral conductor an annual apparent demand forecast is calculated for each season of the year (for the time interval of system peak demand). The per-unit contribution of each Load Group to the apparent demand in each season in year 1 is used (as calculated in the load loss energy calculations) in this calculation. The pro-rata contributions of each Load Group demand forecast are summated (using the per-unit contribution of each Load Group) to obtain the phase/neutral conductor annual apparent demand forecast for each season of the year.

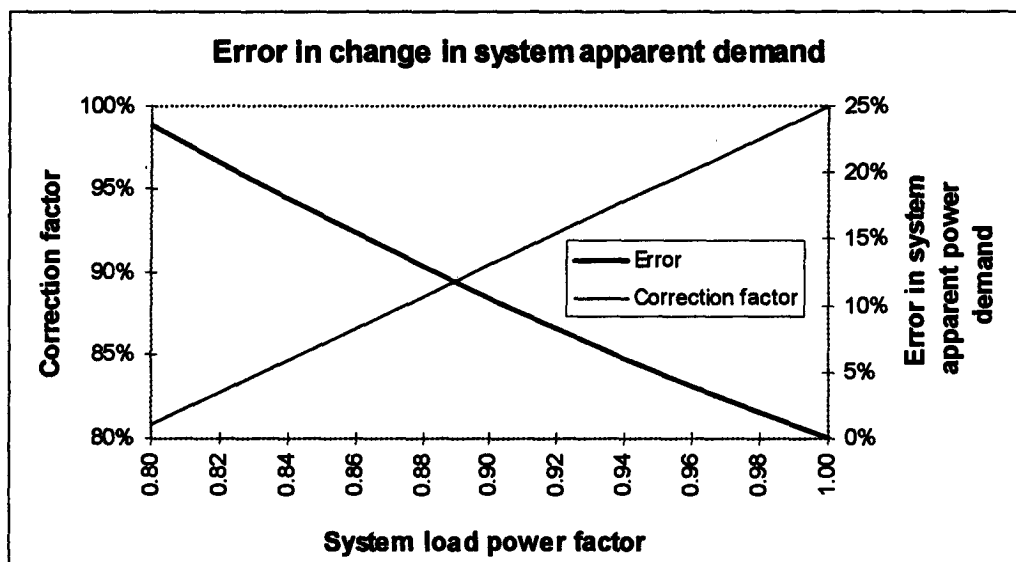
### Year y effective cost of load loss demand

The effective cost of load loss demand (incorporating the effect of voltage drop and load voltage dependency) at the time of system peak is dependent of the Utility Loss Tariff and load demand voltage dependency. Load Groups and Fixed Loads can have different voltage dependencies. The effective cost of load loss demand is dependent on the contribution of each Fixed Load and Load Group to the load loss demand at the time interval of system peak. The per-unit contributions (as calculated in the load loss energy calculations) are combined with the Load Group demand forecasts, load demand voltage dependency and Utility Loss Tariff demand charges to calculate the effective cost of load loss demand at the system peak time interval for each season in each year. The effects of auto-tapping

transformers and voltage regulators on downstream load demand voltage dependency are taken into consideration.

The load loss demand costs are based on active load loss power. Reactive load loss power is not included in the method for load loss demand costing. This approach is valid if the Utility Loss Tariff demand charges are based on active power demand. Errors arise if the system peak load power factor is not unity and active load loss demands are used with a Utility Loss Tariff that has apparent power demand charges.

Figure 11.2.1.1: Error in maximum demand charge (and associated correction factor) if active load loss demand is used with an apparent power demand charge



Referring to figure 11.2.1.1, load loss demand costs will be significantly overstated if the system load power factor is less than 0.95 and active load loss is used with an apparent demand charge. If the expected system load power factor is known, the appropriate correction factor can be applied. Referring to figure 11.2.1.1, if the system load power factor is 0.90 the active load loss demand must be multiplied by 0.9045.

Lifetime load loss demand cost (extrapolation of year 1 results)

The load loss demand for the system peak time interval in each season in each future year is calculated using the year 1 load loss demand and seasonal apparent demand forecast. As with the load loss energy calculations, the change in future year load loss demand relative to

year 1 is assumed to be proportional to the square of the per-unit change in apparent demand. This assumption is valid for constant current loads.

The lifetime load loss demand cost is obtained by multiplying the load loss demand and effective load loss demand costs in each season in each year, and discounting to present value (year 1) using the Net Discount Rate.

### 11.2.2 Load loss demand testing

The load loss demand is based on the average load loss in a particular time interval. The load model and assumptions used in the load loss demand calculation are the same as for the load loss energy calculation. The lifetime load loss demand test results for the NRS034 LV feeders supplying a mixture of different consumer load classes (described in section 11.1.4) are summarised in table 11.2.2.1. Test results are for the 18:00 weekday time interval. The same lifetime, Net Discount Rates etc were used as for the load loss energy tests. Utility Loss Tariff demand charges are based on the Eskom WEPS [Eskom, 2005b] as per appendix I.

Network	Result	Load loss demand cost [Rand]	Load loss demand cost error [%]
NRS 034 Case 5 (star and single phase)	Monte Carlo simulation	R 26.04	N/A
	Proposed method	R 26.55	1.97%
NRS 034 Case 6 (bi-phase and single phase)	Monte Carlo simulation	R 32.34	N/A
	Proposed method	R 32.73	1.20%
NRS 034 Modified Case 3 (delta)	Monte Carlo simulation	R 31.55	N/A
	Proposed method	R 31.56	0.06%

Table 11.2.2.1: Mixed load 10 year average load loss demand evaluation. Errors are differences relative to the Monte Carlo simulation

Referring to table 11.2.2.1, the errors in the proposed method for the calculation and costing of the average load loss demand in a user defined time interval are small (<2% for the tested networks) and within practical planning and design requirements. The method used to mix load classes and account for different growth rates gives acceptably accurate lifetime load loss demand costs.

### **11.3 NO-LOAD LOSS ENERGY AND DEMAND CALCULATION AND COSTING**

The no-load loss energy and demand calculation and costing is detailed in appendix E. No-load loss costs are calculated with the following features and assumptions:

- No-load loss energy and demand are assumed constant over the entire evaluation period.
- Active no-load loss energy costs are based on the Utility Loss Tariff charges (active energy charge in each time interval), Utility Loss Tariff energy forecast, the evaluation period and the Net Discount Rate.
- Reactive no-load loss energy costs are based on fixed shunt capacitor lifetime costs, the number of hours in the evaluation period and the Net Discount Rate. Shunt capacitor capital and operating and maintenance costs are assumed to escalate at the general inflation rate.
- No-load loss demand costs are based on active no-load loss demand (as with load loss demand costing). No-load loss demand costs are dependent on the Utility Loss Tariff (demand charge in each season of the year), Utility Loss Tariff demand forecast, the evaluation period and the Net Discount Rate.

Note that no-load losses are constant and will coincide with the system maximum demand.

### **11.4 BRANCH CONDUCTOR SIZE OPTIMISATION**

The conductor size optimisation is detailed in appendix E, and minimises the sum of the conductor capital and effective lifetime load loss energy and load loss demand costs for each branch (incorporates conductor voltage drop and load voltage dependency). The maximum current in each phase/neural is calculated and used to constrain the optimisation such that conductor thermal current ratings are not exceeded. The optimisation is confined to conductor size (lines and cables) and excludes transformers.

#### 11.4.1 Peak load calculation

The conductor size optimisation is constrained by the conductor thermal current rating and the maximum conductor current in a user defined year. The maximum current in each phase/neutral conductor in the user defined year is calculated as follows:

- The mean and standard deviation of the conductor load current are calculated in each time interval in year 1 (available from the load loss energy calculations).
- The time interval of conductor maximum mean loading in year 1 is identified.
- The conductor maximum peak loading in this time interval in year 1 is obtained by adding the mean and a user defined number of standard deviations.
- The conductor maximum peak loading in the user defined year is calculated using the maximum peak loading in year 1 and the apparent demand forecast (available from the load loss energy calculations).

#### 11.4.2 Conductor size optimisation

The branch conductor size optimisation is performed with the following features and assumptions:

- The load loss calculations described in sections 11.1 and 11.2 are performed for each phase/neutral conductor. Branch conductor size optimisation requires that all of the phase and neutral (where applicable) conductors in a branch are analysed as an entity. As a result the terminology "cable/line" is henceforth used to describe a branch consisting of a number of phase and neutral (where applicable) conductors.
- The phase conductors of each cable/line are the same size. The neutral conductor size may be different to that of the phase conductor.
- For each branch the user specifies a list of cable/line sizes for consideration.
- The load loss calculations described in sections 11.1 and 11.2 provide normalised  $[Rand/\Omega]$  lifetime load loss costs for each phase/neutral conductor. The lifetime load loss and voltage drop cost is calculated for each of the cables/lines in the list.
- The optimal cable/line in a branch minimises the sum of the cable/line capital and lifetime load loss and voltage drop cost in that branch, and meets the thermal rating requirement.
- No regression or non-linear optimisation techniques are required as the number of conductors for possible selection is sufficiently small such that an exhaustive search can be practically performed. As a constant current load model is used, cable/line sizes do

not affect the normalised lifetime load loss and voltage drop costs (different branch impedances do not affect branch currents).

- As per Sellick [1999], it is assumed that the operating and maintenance costs associated with different cables/lines (for the same voltage level and technology e.g. buried 1kV PVC copper 3 phase 4 wire cables) do not vary significantly, and are hence excluded from the evaluation.
- The optimisation is not constrained by a maximum voltage drop limit or minimum voltage. A voltage drop limit or minimum voltage requirement could be implemented by incorporating the statistical calculations in this research with an iterative conductor optimisation routine such as described by Falaghi et al [2005].

## 11.5 CONDUCTOR LIFETIME COST RESULTS

The loss analysis results are detailed in appendix E. The following results are calculated for each branch cable/line:

- The optimal cable/line size (as selected from a user defined list).
- Capital cost.
- Lifetime active load loss energy and active load loss energy and voltage drop cost.
- Lifetime reactive load loss energy and reactive load loss energy cost.
- Lifetime active load loss demand cost.
- Lifetime load loss and voltage drop cost (energy and demand, active and reactive).
- Lifetime capital, load loss and voltage drop cost.
- Maximum phases/neutral loading in a user defined year.
- Lifetime load loss cost per kW and kVAr of load loss during peak loading in a user defined year.

## 11.6 SUMMARY AND CONCLUSIONS

A statistically based loss calculation and costing method has been developed for radial distribution networks. The method has the following main features (some of which are requirements as identified in sections 5.5, 6.3 and 10.6) considered appropriate for the optimisation of conductor sizes in South African domestic electrification networks:

- It applies to radial MV and LV balanced and unbalanced network technologies and loads.

- Load classes are described by Load Groups with daily load profiles for each day type in each season. Future load changes are described by annual energy and demand load forecasts for each Load Group.
- Load losses are calculated in each time interval of each day type in each season. The effect of load balancing (at peak loading and other time periods) is modelled.  
The stochastic nature of the loads is modelled using parameters describing both the mean and variance of the loads.  
Fixed and variable loads (with different load shapes, power factors and load forecasts) can be combined in the same network analysis. Load power factor is modelled.
- Load loss energy and demand calculations are based on constant current load models. The likely errors for loads that are not constant current have been shown to be relatively small (section 9.5).
- The calculations are performed separately for each phase/neutral conductor. Neutral conductor losses are explicitly calculated.
- Active load loss energy costs are based on the time-of-use Utility Loss Tariff, Customer Tariffs and consumer energy voltage dependency. The load loss energy costs for each conductor incorporates the missed opportunity cost due to changes in downstream consumer energy consumption as a result of load voltage dependency and conductor voltage drop.
- Load loss demand costing is performed for a user defined time and day type. The diversity of the load loss demand with upstream network/generation loading is explicitly modelled.
- Active load loss demand costs are based on the Utility Loss Tariff demand charge and consumer demand voltage dependency. It is assumed that customers do not pay demand charges.
- Reactive load and no-load loss energy costs are based on switched and fixed shunt capacitor lifetime costs respectively.
- The lifetime load loss energy, voltage drop and demand costs are expressed as a Net Present Value using the evaluation period, Load Group load forecasts, Utility Loss Tariff forecast, Customer Tariff forecasts and Net Discount Rate.
- The network topology is constant for the entire evaluation period.
- A forecast limit can be applied to account for future network upgrades/additions.
- No-load losses, shunt capacitors, transformers, and DETS tap settings are accounted for in the calculations. As load-flow is not performed in each time interval, the effect of auto-tapping and shunt capacitor switching on load loss is not modelled.

- The conductor size in each branch is optimised to minimise the sum of the branch capital and lifetime technical load loss and voltage drop costs. The conductor optimisation is constrained by conductor thermal ratings.
- Loss analysis results are calculated for each line and transformer. Summary results are provided for the study network.

Monte Carlo simulation was used to test the proposed method and the Loss Load Factor and average load profile multiple time interval load-flow methods described in chapter 5 and identified as needing to be tested. The results are based on South African domestic load research data. The findings and conclusions should also be applicable to other countries:

- The errors in the Loss Load Factor and average profile load-flow methods are large (-55.7% and -35.6% respectively for the tested networks) when applied to LV networks supplying domestic loads. The results of optimisation techniques utilising these methods (such as the conductor size optimisation performed by Falaghi et al [2005]) may be seriously compromised.
- The errors in the Loss Load Factor and average profile load-flow methods increase further if the effect of load voltage dependency and voltage drop is included in the effective cost of conductor load loss energy.
- The errors in the proposed method are small and within practical planning and design requirements.
- The proposed method requires additional effort in the derivation of load parameters and the computation of losses. The additional effort is justified due to the large improvement in accuracy.

## 11.7 LOOKING FORWARD

The optimal conductor sizes (as calculated in the loss calculation and costing method) are inputs to the voltage drop calculations described in the next chapters.

The application of the proposed method (including the statistical time-of-use loss calculations, time-of-use loss costing and missed opportunity costs due to voltage drop and load voltage dependency) may result in different optimal conductor sizes as compared to traditional loss calculation and costing methods. The impact and relevance needs to be tested on a sample South African rural domestic electrification network.

## **12. ENHANCED QOS LV VOLTAGE DROP CALCULATION**

The QOS voltage drop calculation introduced in section 4.2.2 was identified for possible application in this research. In this chapter enhancements are made to the QOS method to support mixed Load Groups and improve accuracy within 1 hour intervals. The accuracy of the enhanced QOS method is demonstrated on benchmark networks via comparison of the calculated voltages with Monte Carlo simulation results for different South African domestic communities.

### **12.1 ENHANCED QOS METHOD**

The QOS load model and voltage drop calculation introduced in section 4.2.2 is described by Heunis [2000] and Heunis [2003].

Referring to section 7.8.1, the suitability of the approximations and beta distribution used in the QOS method needed to be tested when applied within 1 hour time intervals. Initial testing of the QOS method via Monte Carlo simulation identified deficiencies in the original method when applied to a 1 hour time interval.

Referring to appendix G, three enhancements have been made to the QOS voltage drop calculation method:

- 1) The calculation of the beta voltage distribution maximum and minimum limits is performed using the consumer circuit breaker rating and individual consumer percentile currents. This approach was found to improve accuracy and does not require the use of an arbitrary number of standard deviations as is the case in the original calculation.
- 2) The variance of the standard deviation of load currents has been included. The error in the calculated percentile voltage within 1 hour time intervals was found to increase significantly if the variance of the standard deviation of load currents is ignored.

- 3) Consumers from different Load Groups are combined in the voltage drop calculation assuming zero correlation between Load Groups within 1 hour intervals.

## 12.2 QOS LV VOLTAGE DROP CALCULATION TESTING

### 12.2.1 Monte Carlo simulation

The Monte Carlo simulation software used for the energy loss testing was further enhanced by Dr Heunis to extract percentile voltages within 1 hour time intervals (see appendix F). 1000 iterations have been used for voltage drop assessment.

The Monte Carlo simulation of LV voltage drops uses the same assumptions as the QOS method; constant current unity power factor loads, and network reactance is ignored. Referring to chapter 9, for South African domestic electrification networks the likely errors due to these assumptions are small. Comparison with Monte Carlo simulation only tests the accuracy of the calculations used to account for the stochastic nature of the load.

### 12.2.2 LV networks with homogeneous domestic customers

Testing is confined to domestic customers from the same community (Load Group). Results for mixed communities are provided in section 12.2.3.

#### Single node

The QOS voltage drop calculation is based on a constant current load model, and is a linear combination of load currents that are scaled by the phase and neutral resistances and phase connections (current angles). The accuracy of the load model can be tested for different consumer numbers using a single branch/node.

Referring to appendix G.2, tests were performed comparing the calculated and simulated (via Monte Carlo simulation) voltages for a range of input variables:

- Percentile voltages (p): 0.975, 0.95.
- Confidence level (cl): 0.9 and 0.5
- Customer numbers (N): 2, 3, 5, 10 and 20.
- Communities: 2000 Orient, 2002 Antioch, 2002 Mfazazane and 2002 Welgemoed.

The results for 5 consumers in 2000 Orient are illustrated in figure 12.2.2.1 for each of the day types and 1 hour intervals ( $p=0.975$ ,  $cl=0.9$ ).

Figure 12.2.2.1: Single node results for 2000 Orient ( $p=0.975$ ,  $cl=0.9$ ,  $N=5$ )

**Simulated versus calculated voltages: Single node N=5, 2000 Orient**

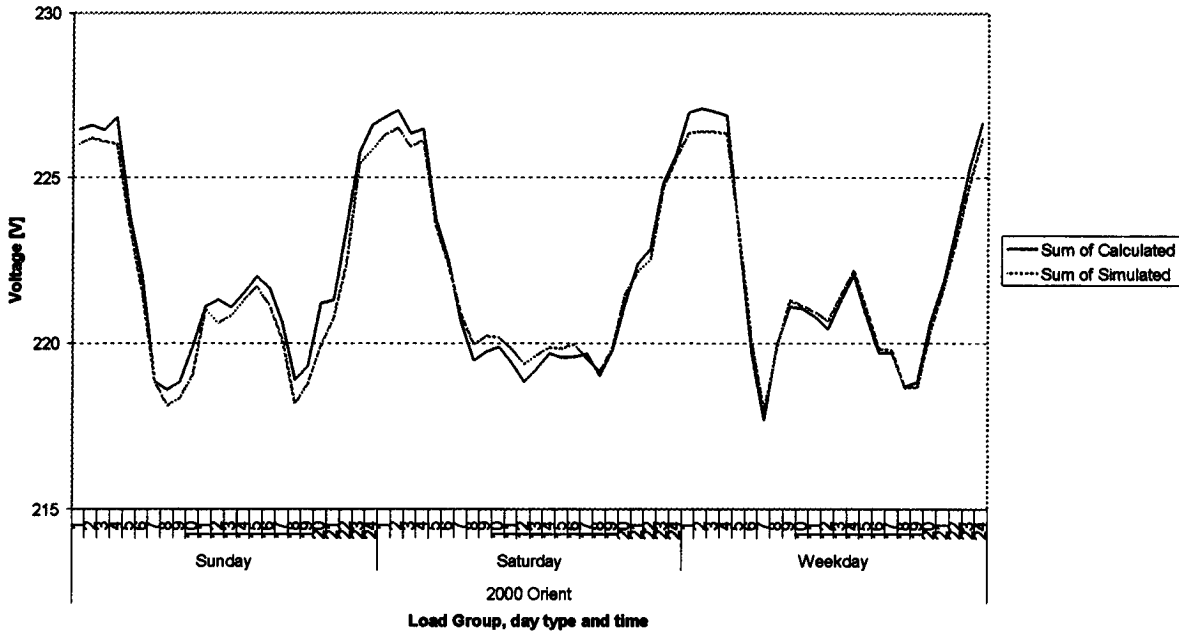
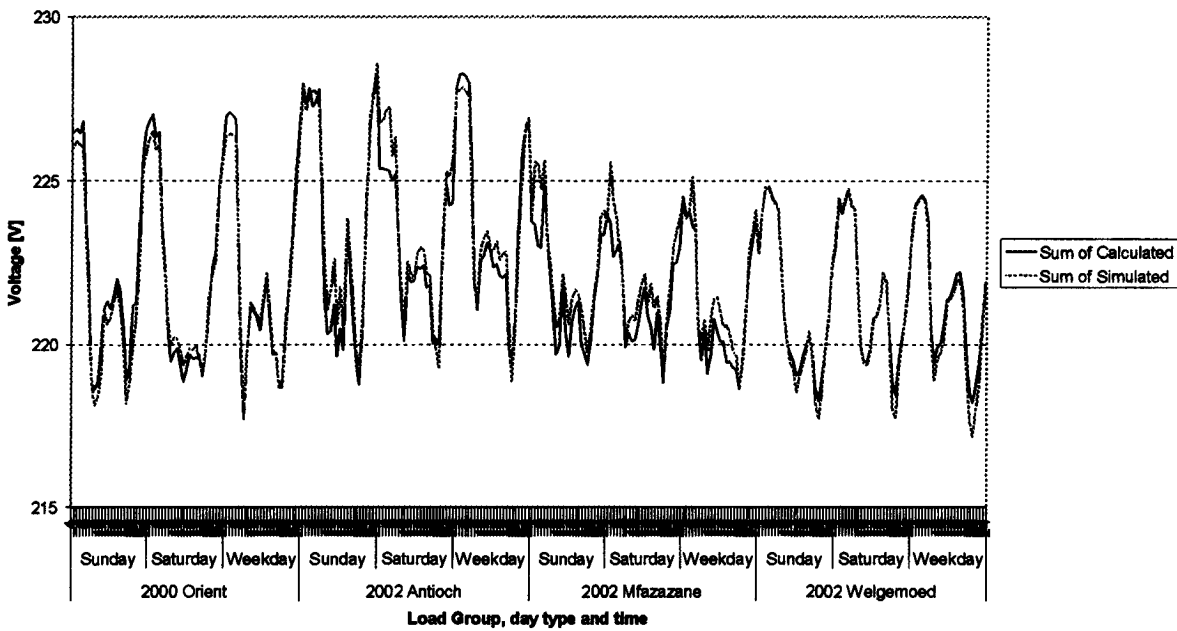


Figure 12.2.2.2: Single node results ( $p=0.975$ ,  $cl=0.9$ ,  $N=5$ )

**Simulated versus calculated voltages: Single node N=5**



The results for all of the selected load groups ( $p=0.975$ ,  $cl=0.9$ ,  $N=5$ ) are plotted in figure 12.2.2.2. The results for the other percentiles, confidence levels and customer numbers are contained in appendix G.

Multiple node networks

Tests were performed using the benchmark three phase star (NRS034 Case 5) and bi-phase (NRS034 Case 6) networks described in section 11.1.4. Communities 2002 Antioch, 2002 Mfazazane and 2002 Welgemoed were used. A percentile voltage of 97.5% and confidence level of 90% were used. The results for the three phase and bi-phase networks are plotted in figures 12.2.2.3 and 12.2.2.4 respectively for each of the three load groups, day types and 1 hour intervals.

Figure 12.2.2.3: Three phase star (NRS034 Case 5) network results (July 2002, homogenous customers,  $p=0.975$ ,  $cl=0.9$ ). Minimum voltage at node H

**Simulated versus calculated voltages: Three phase NRS034 Case 5**

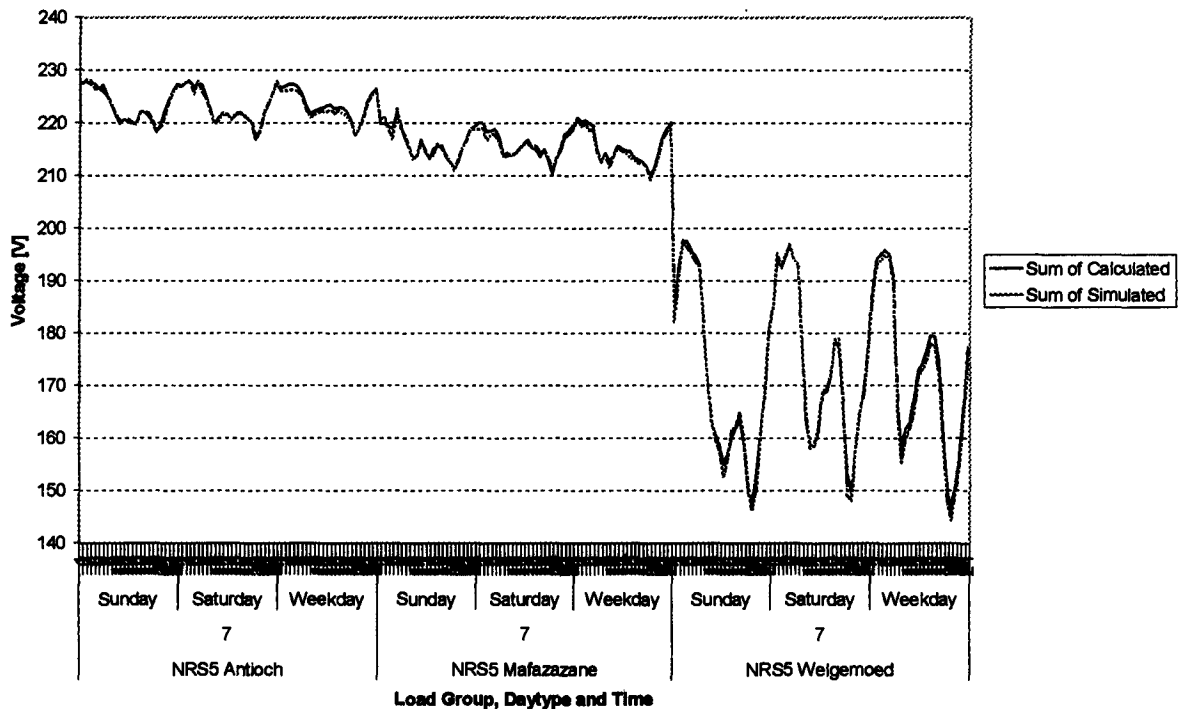
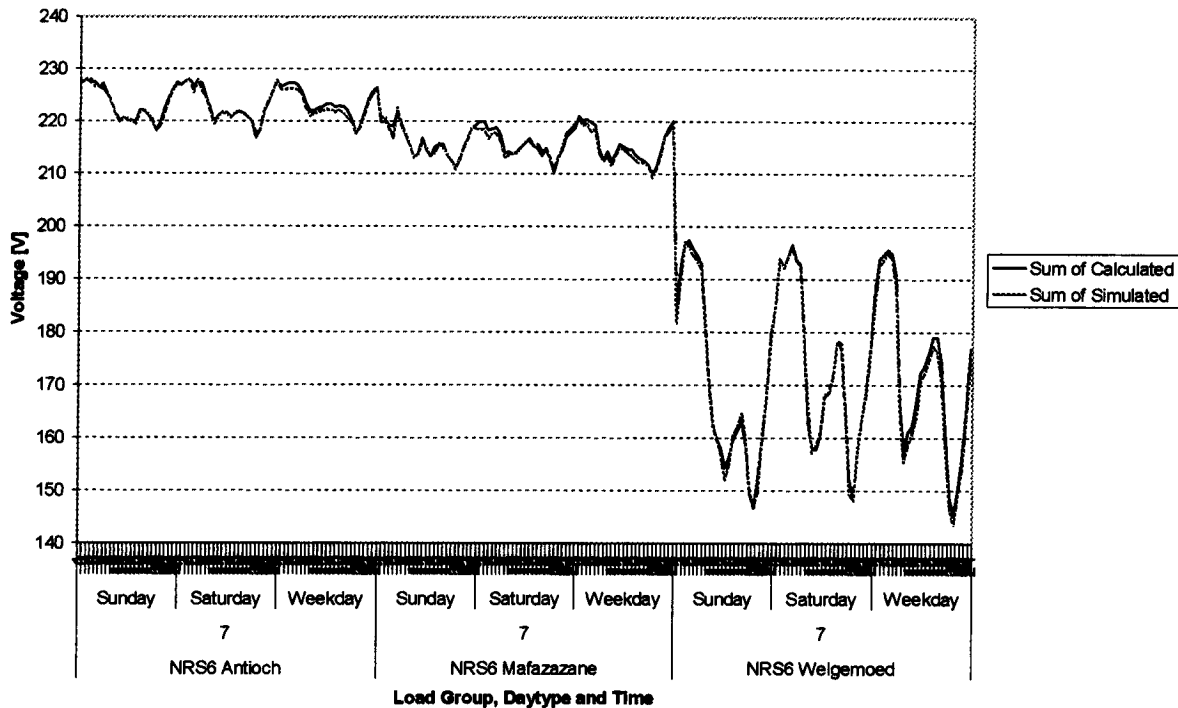


Figure 12.2.2.4: Bi-phase (NRS034 Case 6) network results (July 2002, homogeneous customers,  $p=0.975$ ,  $cl=0.9$ ). Minimum voltage at node H

Simulated versus calculated voltages: Bi-phase NRS034 Case 6



The differences between the simulated and calculated values are small and within practical planning and design requirements.

Comparing figures 12.2.2.3 and 12.2.2.4 it is interesting to note that the bi-phase network voltage drop is similar to that of the three phase network using the same size conductors (the bi-phase network has one less phase conductor so the effective conductor size is smaller). This supports the findings by Herman et al [1998].

### 12.2.3 LV networks with mixed domestic customers

Tests were performed on the star (NRS034 Case 5) and bi-phase (NRS034 Case 6) networks modified for the mixing of consumer Load Groups (see section 11.1.4 and figures 11.1.4.4 and 11.1.4.5). Tests were performed with communities 2002 Antioch, 2002 Mfrazazane and 2002 Welgemoed for Load Groups L1, L2 and L3 respectively. The results for a percentile voltage of 97.5% and confidence level of 90% are provided in figures 12.2.3.1 and 12.2.3.2.

Figure 12.2.3.1: Three phase star (NRS034 Case 5) network results (July 2002, mixed customers,  $p=0.975$ ,  $cl=0.9$ ). Minimum voltage at node H

Simulated versus calculated voltages: Three phase NRS034 Case 5 Mixed

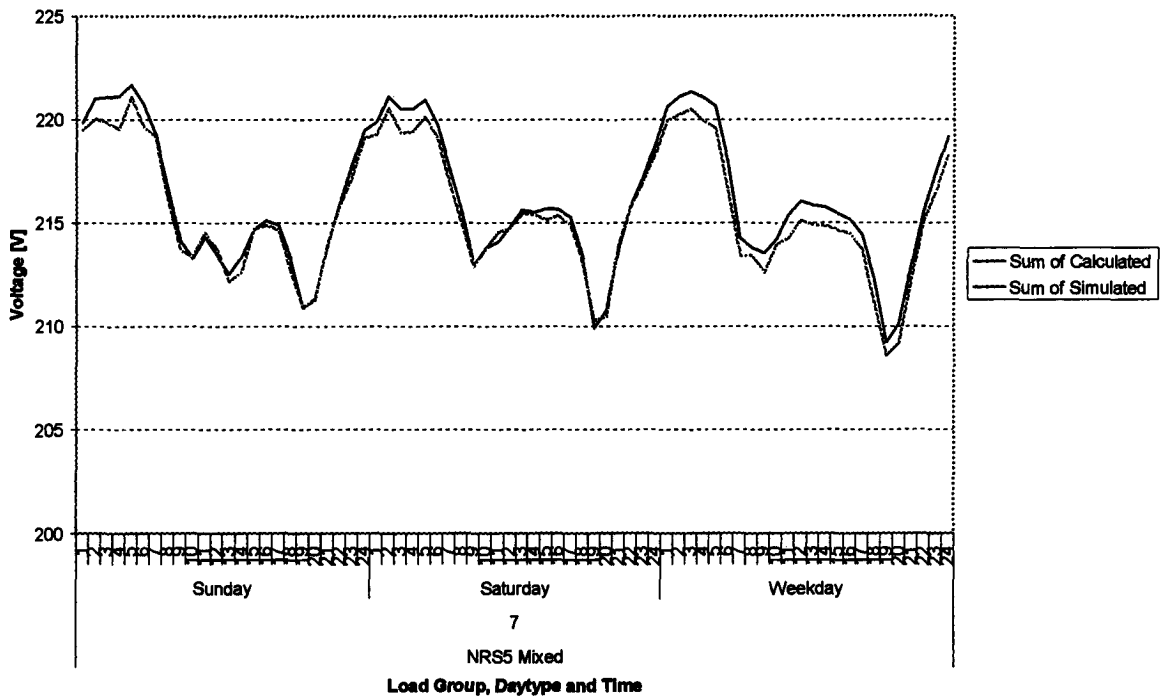
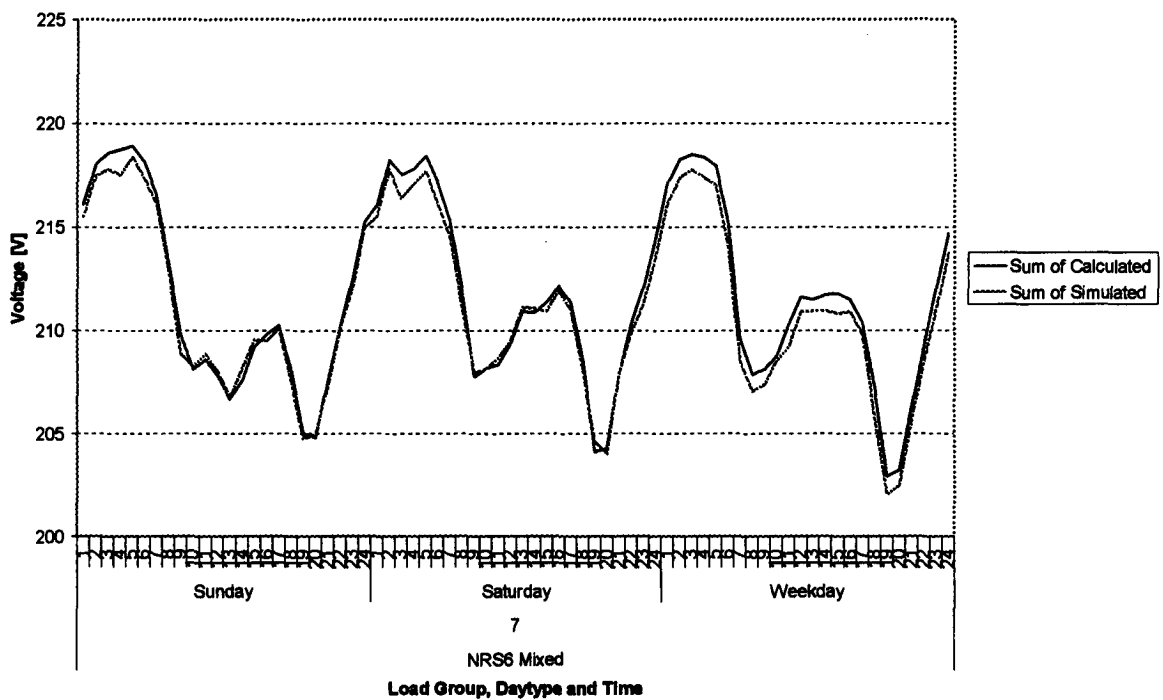


Figure 12.2.3.2: Bi-phase phase (NRS034 Case 6) network results (July 2002, mixed customers,  $p=0.975$ ,  $cl=0.9$ ). Minimum voltage at node H

Simulated versus calculated voltages: Bi-phase NRS034 Case 6 Mixed



The calculated and simulated voltages compare favourably, validating the assumption that correlation between Load Groups can be ignored within 1 hour intervals (raised in section 7.8.1).

#### 12.2.4 LV networks with non-domestic customers

Due to limited South African non-domestic load research data, the QOS LV voltage drop calculations have only been tested with domestic consumers. The method caters for non-domestic consumers (raised in section 4.2.2). Non-domestic consumers can be modelled in one of three ways:

- a) As Fixed Loads. The errors in voltage drop and load loss calculations at different time intervals may be large.
- b) As Load Groups where the correlation between non-domestic consumers in the same Load Group is ignored. The Load Group mean and standard deviation in each time interval is described, however the load parameters used to account for correlation and risk are not specified.
- c) As Load Groups where same load parameters are used as for domestic consumer Load Groups.

The approach used for the modelling of non-domestic loads will depend on the availability of suitable load data.

The QOS load model is based on a beta distribution. The beta distribution is bounded and can be left skewed, right skewed or centered. The beta distribution is expected to be appropriate for the modelling of non-domestic loads.

### 12.3 SUMMARY AND CONCLUSIONS

The QOS LV voltage drop calculation method has been enhanced thereby supporting mixed Load Groups and improving accuracy when applied within 1 hour intervals. The accuracy of the enhanced method has been tested via Monte Carlo simulation using benchmark networks exhibiting the characteristics of practical South African domestic LV feeders. The load research data is representative of a wide range of South African domestic communities. The LV percentile voltage drop in each 1 hour interval can be calculated for a user defined confidence level. Errors are acceptable for practical planning and design. The beta distribution is appropriate for the modelling of domestic consumer voltage drop.

## 12.4 LOOKING FORWARD

The QOS LV voltage drop calculation needs to be combined with MV voltage drop and MV/LV transformer voltage drop calculations to calculate the percentile LV voltage at customer installations for a user defined confidence level, time of day, day type, season and year.

## **13. MV VOLTAGE DROP CALCULATION**

A method is required for the time-of-use calculation of the percentile MV voltage drop in radial South African domestic electrification networks. Three deterministic MV methods have been identified for testing. All three methods use the QOS load model to calculate MV “bulk” loads connected at the MV/LV distribution transformer locations and/or MV laterals. The methods differ in the approaches used to model load diversity.

Due to the requirement to sample with replacement, the Monte Carlo simulation of MV networks cannot be used to test each of the three methods. The QOS load model is used to test the load diversity modelling accuracy of each of the three methods. Only one of the methods (method 2) provides acceptable accuracy, and is adopted for this research.

### **13.1 COMPARISON OF DETERMINISTIC OPTIONS**

Referring to section 9.4, network reactance and load power factor need to be modelled for MV voltage drop calculation. The QOS load model in its present form cannot be applied directly to MV networks.

Deterministic load-flow (as implemented in utility and commercial load-flow packages) models network reactance and load power factor. Referring to section 4.3.2, three deterministic MV voltage drop calculation methods have been identified for possible adoption:

1. Undiversified MV loads: The MV/LV distribution transformer loads are modelled as “bulk” loads at the MV terminals of the distribution transformers. The MV bulk load at each distribution transformer is based on the load mean and variance for the number of customers supplied by that distribution transformer (MV bulk loads are not diversified).
2. Diversified MV loads: The MV/LV distribution transformer loads are modelled as “bulk” loads at the MV terminals of the distribution transformers. The MV bulk load at each distribution transformer is based on the normalised load mean and variance for the

number of customers supplied by the entire MV network (MV bulk loads are diversified) multiplied by the number of customers supplied by that distribution transformer.

3. Undiversified loads lumped onto MV laterals: MV lateral line loadings are lumped onto the MV primary as MV bulk loads, where each MV bulk load is calculated based on the load mean and variance for the number of customers supplied by that MV lateral. Only the MV network between the MV source and MV lateral with expected minimum MV voltage is modelled.

In all three of the above deterministic methods the probabilistic QOS load model is used to calculate the magnitude of the “bulk” loads connected to the MV network for each time interval, day type, season and year. The power factor of the bulk load is modelled. The methods are probabilistic to the extent that each of the bulk loads is based on a probabilistic load model however no further diversity between bulk loads is modelled.

Fixed Loads are included in the “bulk” loads such that both fixed and variable loads are included in the MV voltage drop calculations.

Due to the limited number of customers sampled for each community, Monte Carlo simulation for MV networks can only be performed with replacement, and the variance of the load will be overstated (see section 11.1.4). The expected errors in the Monte Carlo simulation of the MV voltage drop is expected to be greater than for the energy losses as the loss calculations only consider average loss. The voltage drop calculations consider both a percentile value and confidence level, both of which are sensitive to errors in the load variance. Referring to table 13.1.1, the errors in the Monte Carlo simulation voltage drop due to replacement are unacceptably large. Comparison of MV voltage drop calculations with Monte Carlo simulation results is misleading.

Load Group	N <sub>r</sub>	Difference [%]
2002 Antioch	52	23.68%
2002 Mfazazana	47	20.67%
2002 Weigemoed	49	14.47%

Table 13.1.1: Difference between Monte Carlo simulated voltage drop with and without consumer replacement (June 2002, Weekday, 19:00, p=0.975, cl=0.9). Results are relative to simulation without replacement

The three MV deterministic methods model load voltage dependency, power factor and network reactance. The errors in the three methods arise due to their treatment of load

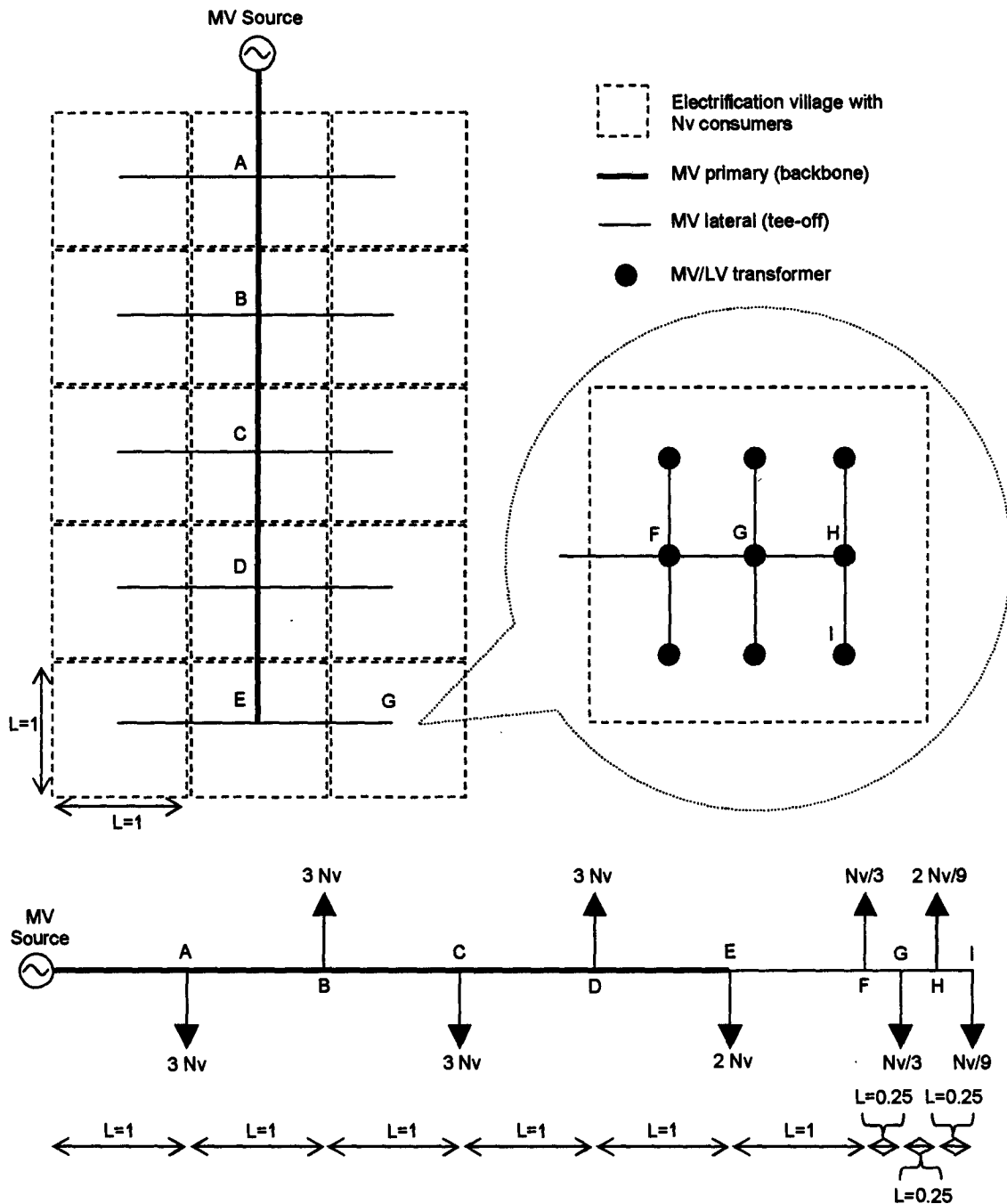
diversity in the upstream MV network. Referring to chapter 12, the accuracy of the QOS load model has been demonstrated within the assumptions of a constant current load model, unity power factor and zero reactance. Comparison with the QOS load model can be used to assess the diversity related errors in the MV deterministic methods. The comparison with the QOS load model does not reflect the total accuracy of the MV deterministic methods, but rather the accuracy relating to the modelling of load diversity. Additional errors may arise due to errors in network impedance models and load-flow calculations, but are beyond the scope of this research.

A benchmark MV network is required for testing of the three MV deterministic methods. The IEEE 12.66kV test network used by Stojanovic et al [1999] is not representative of South African rural networks, which are characterised by delta line technologies and numerous small (<50kVA) distribution transformers. It is unlikely to obtain a single benchmark network that is representative of most South African rural domestic electrification applications.

For the purposes of this research a generic rural domestic electrification MV network model was created, whereby sensitivity analysis can be performed on the major network characteristics including; the number of customer supplied per MV/LV distribution transformer and the total number of customers supplied by the MV feeder.

Referring to figure 13.1.1, the MV voltage drop between the MV source and the last MV node (node I) is modelled as an equivalent network with lumped loads that are multiples of the number of consumers connected at each "village". The line lengths between nodes will vary depending on customer density. The relative lengths are important for this analysis as the differences in voltage drops are important, not the minimum voltages (a constant current load model is used so the relative change in voltage drop is independent of the total voltage drop). In reality the network structure varies due to non-uniform customer settlement topology and constrained line routing, but the generic network is sufficient for the requirements of this analysis.

Figure 13.1.1: Generic rural domestic electrification MV feeder



The inputs for the generic rural domestic electrification MV network model are:

- $N_v$  Average number of consumers per village
- $T$  Average number of consumers per MV/LV distribution transformer
- $R_{ratio}$  Ratio of the per km resistance of the MV lateral versus MV primary conductors [ratio]

The outputs from the generic rural domestic electrification MV network model are:

- NMV Total number of consumers supplied by MV feeder =  $15 \cdot N_v$
- $E_{m1}$  Method 1 MV voltage drop error relative to QOS method [%]
- $E_{m2}$  Method 2 MV voltage drop error relative to QOS method [%]
- $E_{m3}$  Method 3 MV voltage drop error relative to QOS method [%]

In Eskom Distribution rural overhead MV networks, Hare (123mm<sup>2</sup> ACSR) and Fox (43mm<sup>2</sup> ACSR) conductors are commonly used for MV primary and MV lateral conductors respectively. Referring to appendix J, Hare and Fox conductor AC resistances are 0.296Ω/km and 0.845Ω/km respectively.  $R_{ratio}=2.5$  was used for this analysis.

The generic network model results for the peak loading time interval with the 2002 Welgemoed load group data are summarised in table 13.1.2. Appendix H contains results for 2002 Welgemoed, 2002 Mfazazane and 2002 Antioch load groups at evening-peak, mid-day and early-morning time intervals.

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	53.99%	30.89%	16.54%	N/A	N/A
Method 2: Diversified MV loads	-2.82%	-2.82%	-2.82%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	13.43%	13.43%	13.43%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	57.78%	34.12%	19.41%	10.37%	N/A
Method 2: Diversified MV loads	-1.78%	-1.78%	-1.78%	-1.78%	N/A
Method 3: Undiversified loads lumped onto MV laterals	8.49%	8.49%	8.49%	8.49%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	60.84%	36.72%	21.73%	12.51%	5.60%
Method 2: Diversified MV loads	-0.98%	-0.98%	-0.98%	-0.98%	-0.98%
Method 3: Undiversified loads lumped onto MV laterals	4.60%	4.60%	4.60%	4.60%	4.60%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	62.24%	37.91%	22.79%	13.49%	6.52%
Method 2: Diversified MV loads	-0.64%	-0.64%	-0.64%	-0.64%	-0.64%
Method 3: Undiversified loads lumped onto MV laterals	2.91%	2.91%	2.91%	2.91%	2.91%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	62.83%	38.41%	23.23%	13.90%	6.90%
Method 2: Diversified MV loads	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
Method 3: Undiversified loads lumped onto MV laterals	2.24%	2.24%	2.24%	2.24%	2.24%

Table 13.1.2: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Welgemoed, weekday, 18:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

The errors in method 1 are large, and increase as the number of customers supplied per distribution transformer decreases. The average number of customers supplied by each

distribution transformer in the sample network used in chapter 9 is 22. It is the author's experience that in South African rural electrification networks (supplying low-income domestic consumers) T typically falls between 10 and 40 customers per transformer. The associated error for method 1 (table 13.1.2) is between 13.90% and 38.41%. Method 1 is presently applied in the network analysis software used by Eskom Distribution, and significantly overstates the MV voltage drop. This was also confirmed for the other load groups and time intervals (see appendix H).

Modelling the MV lateral loads as percentile loads connected to the MV primary feeder (method 3) reduces the error as compared to method 1, but still overstates the voltage drop. Errors with method 3 increase with reducing NMV, and are of concern when  $NMV < 1500$ . It is the authors experience that many rural domestic electrification MV networks supply less than 1500 consumers. The errors with method 3 are unacceptable.

Method 2 has comparatively low error levels. Table 13.1.3 summarises the method 2 error levels for different time intervals. The loading in the MV lines supplying few customers is understated but the voltage drop in these lines is small as compared to the voltage drop in the MV primary supplying numerous customers. The loading in the MV primary is not significantly understated as the coefficient of variation decreases with increasing customer numbers.

Load interval	Min Error [%]	Max Error [%]	Average Error [%]
Peak-load interval (evening)	-0.50%	-4.14%	-1.72%
Moderate-load interval (mid-day)	1.14%	-7.30%	-2.04%
Low-load interval (early morning)	-0.70%	-9.07%	-3.61%

Table 13.1.3: Method 2 expected error range for 2002 Welgemoed, 2002 Mfazazane and 2002 Antioch load groups ( $p=0.975$ ,  $cl=0.9$ ,  $NMV \geq 600$ )

The error in method 2 was observed to increase in periods of low loading (very early morning) and lower consumption communities. Voltage drop calculation studies are usually focused on the maximum loading interval (minimum voltage). The increased error at lower loading intervals is not expected to be problematic.

The error in method 2 varies for different percentiles and confidence levels as summarised in table 13.1.4. Errors increase with increasing percentile and confidence level.

Percentile (p)	Confidence level (cl)				
	0.5	0.7	0.9	0.95	0.99
0.5	0.09%	-0.57%	-1.48%	-1.89%	-2.64%
0.7	-0.65%	-1.31%	-2.22%	-2.64%	-3.39%
0.9	-1.67%	-2.34%	-3.26%	-3.68%	-4.44%
0.95	-2.14%	-2.81%	-3.74%	-4.16%	-4.93%
0.975	-2.53%	-3.21%	-4.14%	-4.57%	-5.34%
0.99	-2.97%	-3.65%	-4.60%	-5.03%	-5.80%

Table 13.1.4: Method 2 maximum error for 2002 Welgemoed, 2002 Mfazazane and 2002 Antioch load groups in peak-load interval for varying percentile and confidence levels (NMV $\geq$ 600)

Method 2 will be utilised for this research as:

- In practical networks method 2 is expected to underestimate the peak loading MV voltage drop by 0.5% to 4.14% (p=0.975, cl=0.9). This error range is within practical planning and design requirements.
- Method 2 provides acceptable accuracy and the additional complexity introduced by probabilistic MV voltage drop calculation is not justified (raised in section 4.3.2).
- The error in method 2 does not vary with the number of customers supplied per MV/LV transformer.
- Simultaneous calculation can be performed of the voltages at all MV nodes (do not need to perform a separate network equivalence for each MV node).
- Standard load-flow packages and algorithms can be used. These packages/algorithms model load power factor, network reactance, load voltage dependency and MV distribution equipment such as switched shunt capacitors and voltage regulators. The appropriate diversified lumped MV load simply needs to be modelled at each distribution transformer.
- The impact on existing systems and software is minimal yet method 2 provides a large improvement in accuracy as compared to the presently implemented method 1.

Method 2 has not been tested with non-domestic load research data. Method 2 is expected to provide accurate results with non-domestic loads as domestic consumers are already highly stochastic. Method 2 incorporates load power factor and network reactance modelling, which may be important with non-domestic loads.

The MV bulk load calculations for method 2 are provided in appendix H.

## 13.2 SUMMARY AND CONCLUSIONS

Method 1 (undiversified MV loads) is presently used in Eskom Distribution, and significantly overstates the MV voltage drop. The errors in typical applications may exceed 50% and are unacceptably large.

Method 3 (undiversified loads lumped onto MV laterals) results in reduced errors as compared to method 1, but introduces additional computational complexity. The errors in typical applications may exceed 10% and are unacceptably large.

Method 2 (diversified MV loads) can be applied in standard load-flow software. The MV voltage drop is understated. In typical applications the error during peak loading is not expected to exceed -4%. The method is probabilistic to the extent that each of the "bulk" loads lumped onto the MV network is based on the probabilistic QOS load model.

## 13.3 LOOKING FORWARD

Method 2 will be used for this research. The deterministic MV voltage drop calculation needs to be combined with MV/LV transformer and the QOS LV voltage drop calculations to calculate the percentile LV voltage at customer installations for a user defined confidence level, time of day, day type, season and year.

## **14. INTEGRATED SOFTWARE IMPLEMENTATION**

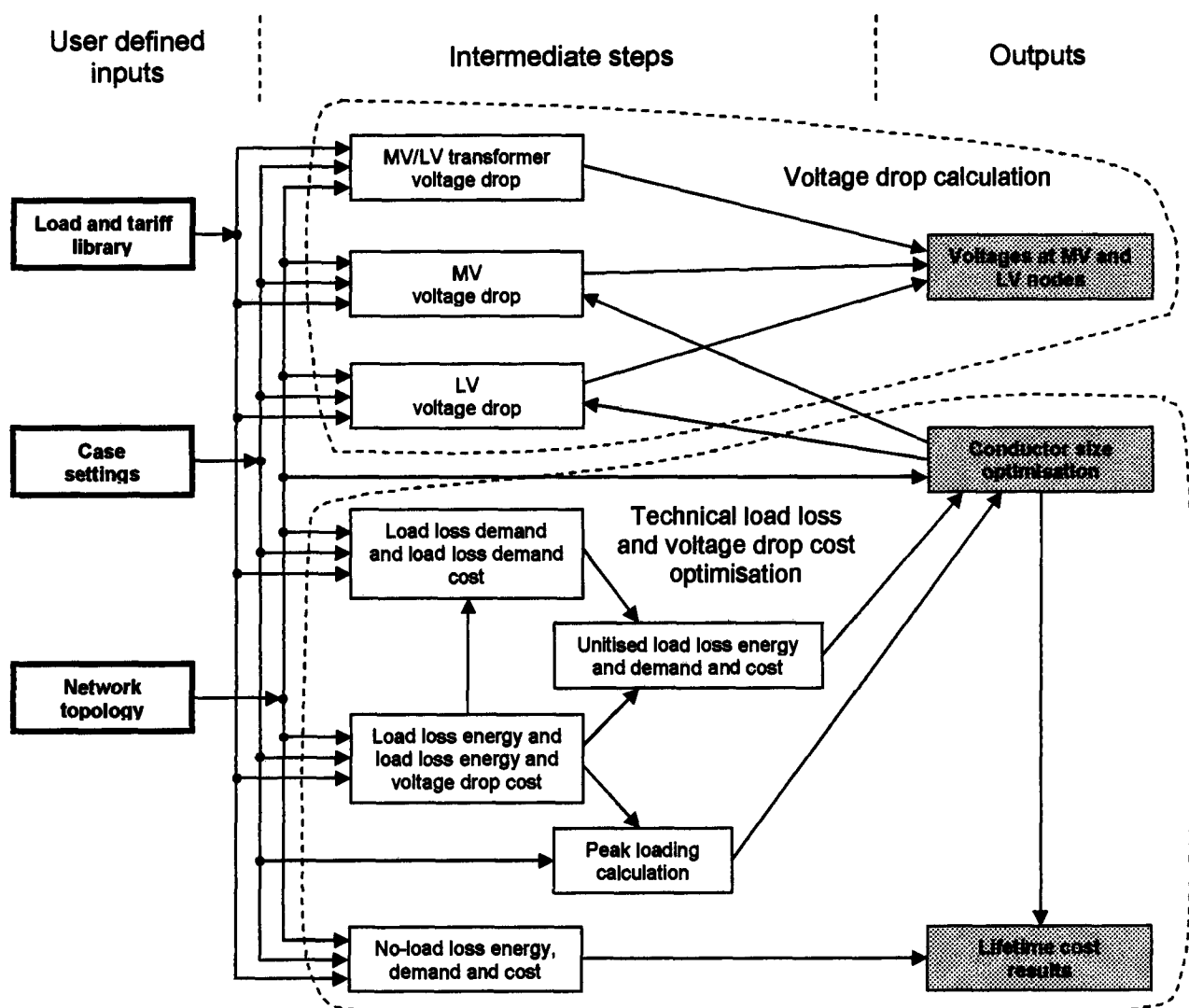
In previous chapters the different components of the proposed method (for conductor size optimisation and the calculation of associated voltage drops) were developed and tested in isolation from one another. In this chapter the components are combined and integrated into South African distribution network analysis software.

### **14.1 COMPONENT INTEGRATION**

The integrated method is summarised in figure 14.1.1. Cells with bold outlines contain the user defined inputs. Shaded cells indicate outputs. Other cells describe intermediate calculation steps. Note that the conductor size is determined by the technical load loss and voltage drop cost optimisation, and is used in the voltage drop calculations.

The integrated method has the features and characteristics described in chapter 7. The loss and voltage drop calculations use the same network model and time-of-use load parameters (raised in section 4.2.2). Additional load parameters (over and above those needed for the load loss calculations) are required to account for risk in the voltage drop calculations. The load loss calculation and LV voltage drop calculation used in the technical loss and voltage drop cost optimisation and voltage drop calculation respectively have been tested via Monte Carlo simulation with South African domestic load research data. The accuracy of the methods has been demonstrated.

Figure 14.1.1: Overview of conductor size optimisation and voltage drop calculation model



The MV voltage drop, MV/LV transformer voltage drop and LV voltage drop calculations are combined as follows:

- 1) The percentile load is calculated at the MV terminals of each distribution MV/LV transformer using the QOS load model and the normalised load mean and variance for the total number of customers supplied by the entire MV network (chapter 13, method 2). For the purposes of MV network load-flow, this load is converted into a bulk load on the MV terminals of the MV/LV transformer. The bulk load includes any Fixed Loads supplied by the MV/LV transformer.
- 2) Deterministic MV load-flow is performed with the transformer fixed loads. Load voltage dependency, power factor and network reactance are considered by these deterministic calculations.

- 3) The calculated voltage at the MV terminals of each of the MV/LV transformers is the MV source voltage for the respective distribution MV/LV transformers.
- 4) The percentile load is calculated at the LV terminals of each MV/LV transformer using the QOS load model, number of consumers supplied by each MV/LV transformer and Fixed Loads. This current is used to calculate the voltage drop over the MV/LV transformer (the transformer reactance and load power factor are included in this calculation). A constant current load model is used. Errors for loads that are not constant current have been shown to be small.
- 5) The MV/LV transformer MV terminal voltages and MV/LV transformer voltage drops are combined to calculate the LV terminal voltages at each MV/LV transformer.
- 6) The LV voltage drop, and minimum LV voltage, is calculated using the QOS voltage drop calculation method and transformer LV terminal voltages.

The percentile LV voltage is calculated for a user defined time interval, day type, season, year and confidence level (raised in section 4.2.1).

## 14.2 IMPLEMENTATION IN NETWORK SIMULATION SOFTWARE

The method was implemented in a South African distribution network load-flow simulation software package called ReticMaster. ReticMaster was chosen as it is Eskom Distribution's preferred network analysis tool for distribution network planning and design. This approach facilitates the application of the system in practical networks. ReticMaster provides a graphical user interface, is integrated with CAD software and can be run in an engine mode whereby the network analysis functionality is initiated via another software application (data is passed to ReticMaster, calculations are performed and the results are posted back).

The implementation was performed by the ReticMaster developers, Inspired Interfaces. A detailed scope of work (containing the methods as detailed in appendices E, G and H) was provided to the developers with associated MathCAD models, test networks and test network results. Comprehensive testing was performed to verify the implementation in ReticMaster. The same test networks described in previous chapters were used for testing and are not repeated here.

### 14.3 LOOKING FORWARD

The method has been implemented in the ReticMaster distribution network load-flow analysis software package. The method must be applied to a South African rural domestic electrification network to demonstrate possible implications for the South African domestic electrification program.

# 15. APPLICATION OF THE PROPOSED METHOD TO A PRACTICAL NETWORK

In this chapter the proposed method for the optimisation of conductor size and calculation of associated voltages is applied to a practical South African rural domestic electrification network. The results are used to assess the relevance of the proposed method.

## 15.1 SAMPLE RURAL DOMESTIC ELECTRIFICATION NETWORK

The sample rural domestic electrification network described in section 9.2 is used to demonstrate the practical application of the proposed method. The following parameters were used:

- All 2188 consumers are assumed to be homogeneous low-income rural domestic customers. Load characteristics are based on the 2002 Antioch load research data. The average monthly energy consumption per consumer is expected to increase from a year 1 consumption of 48kWh to a saturated consumption of 120kWh in year 15. The load forecast is based on relationships between energy consumption, household income, time with electricity and Climatic Severity Index as developed by Heunis and Dekenah [2001].
- A 25 year lifetime and 6% Net Discount Rate are used as is used in Eskom [Eskom, 2005c].
- The Utility Loss Tariff is based on the Eskom 2005 WEPS [Eskom, 2005a] as described in appendix I.
- The Customer Tariff is based on the Eskom 2005 Homelight 1 tariff [Eskom, 2005b] and has a energy charge of 40.68c/kWh.
- The WEPS and Homelight tariff charges are expected to increase as per table 15.1.1. Note that the increases are real price increases i.e. in addition to general inflationary increases.

Year	Per-annum increase [%]
2005 - 2014	2.5%
2015 - 2024	2.0%
2025 - 2033	1.5%

Table 15.1.1: Eskom WEPS and retail customer tariff increases [Eskom, 2005c]

The conductor load loss analysis results for the original network conductor sizes are summarised in table 15.1.2. Results are provided for five values of load energy/demand voltage dependency. For the purposes of this example the revenue recovery rate is assumed to be 90%.

Parameter	Energy and demand voltage dependency				
	K=0	K=0.5	K=1	K=1.5	K=2
Lifetime conductor active load loss energy [MWh]	2145	2145	2145	2145	2145
Lifetime conductor reactive load loss energy [MVArh]	441	441	441	441	441
Lifetime conductor active load loss energy and voltage drop cost [Rand]	R 183,289	R 331,790	R 480,292	R 628,793	R 777,294
Lifetime conductor reactive load loss energy cost [Rand]	R 343	R 343	R 343	R 343	R 343
Lifetime conductor load loss demand cost [Rand]	R 14,346	R 7,173	R 0	-R 7,173	-R 14,346
Lifetime conductor load loss energy, voltage drop and demand cost [Rand]	R 197,977	R 339,306	R 480,634	R 621,963	R 763,292
Conductor capital cost [Rand]	R 13,021,010	R 13,021,010	R 13,021,010	R 13,021,010	R 13,021,010
Lifetime conductor capital and load loss energy, voltage drop and demand cost [Rand]	R 13,218,987	R 13,360,316	R 13,501,644	R 13,642,973	R 13,784,302
Lifetime conductor load loss and voltage drop cost as a % of conductor capital cost [%]	1.52%	2.61%	3.69%	4.78%	5.86%

Table 15.1.2: Sample rural domestic electrification network loss analysis results  
(original conductor sizes)

Referring to table 15.1.2, the lifetime conductor load loss and voltage drop cost increases with increasing load voltage dependency. The lifetime conductor load loss and voltage drop cost is less than 6% of the conductor capital cost.

The voltage drop calculations were performed with the following settings:

- Percentiles of 98.3% and 1.7% were used for the calculation of minimum and maximum voltages respectively and are based on the NRS048-2 [2004] requirement that not more than two consecutive 10-minute voltages can be less than 230V -10% or greater than 230V +10%.

- A confidence level of 90% was used as has historically been used in South African domestic network voltage drop assessment [NRS 034-1, 1999].
- Calculations are in years 7 and 15 (the load is expected to saturate in year 15).

The minimum MV and LV voltages in years 7 and 15 (day type weekday, time interval 19:00 and month 8) are provided in table 15.1.3.

Parameter	Voltage
Minimum MV voltage in year 7 [%]	99.61%
Minimum LV voltage in year 7 [%]	93.34%
Minimum MV voltage in year 15 [%]	98.49%
Minimum LV voltage in year 15 [%]	89.20%

Table 15.1.3: Sample rural domestic electrification network voltage assessment results (original conductor sizes)

The weekday maximum and minimum voltage profiles (month 8 of year 7) are illustrated in figure 15.1.1 for the customer expected to experience the lowest voltage. Consumer voltages are in % on a 230V base.

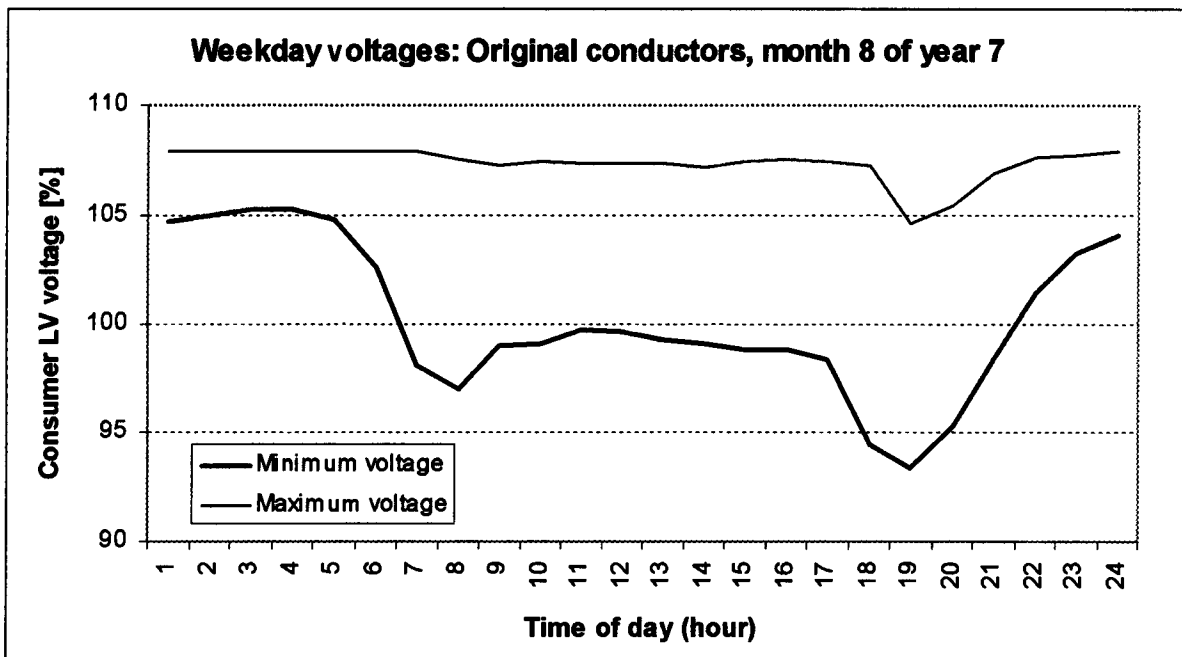


Figure 15.1.1: Maximum and minimum weekday voltages in month 8 of year 7 (original conductor sizes, customer with lowest voltage)

Referring to figure 15.1.1, the year 7 maximum and minimum voltages of 107.93% and 93.34% are within the 230V±10% limit specified by the NRS048-2 [2004]. Referring to table 15.1.3, the year 15 minimum LV voltage is expected to drop marginally below 230V-10% to 89.2%. Voltage control setting or transformer tap setting adjustment may be required to meet the minimum voltage limit in year 15.

The sensitivity of the calculated minimum LV voltage is summarised in table 15.1.4 for different percentiles and confidence levels.

Percentile (p)	Confidence level (cl)		
	0.5	0.9	0.99
0.5	100.49%	99.13%	98.02%
0.9	97.89%	95.86%	94.21%
0.983	95.94%	93.34%	91.23%
0.999	93.59%	90.26%	87.54%

Table 15.1.4: Minimum LV voltage sensitivity to percentile and confidence level  
(weekday, 19:00, month 8 of year 7, original conductor sizes)

Referring to table 15.1.4, the calculated minimum LV voltage is sensitive to both the percentile and confidence level. It is important that the percentile and confidence level are known when evaluating voltage drop calculation results.

The MV and LV conductor sizes were optimised using the proposed method. The impedances, ratings and capital costs of the MV and LV lines/cables used in the optimisation are summarised in table 15.1.5. Detailed conductor parameters are provided in appendix J, and are based on Eskom Distribution line parameters and costs.

Original conductor	Conductors considered in optimisation	Rp+ve [Ω/km]	Rn [Ω/km]	Rating [amps]	Capital Cost [Rand/km]
19kV SWER Squirrel	19kV SWER Squirrel	1.553	N/A	105	R 34,640
	19kV SWER Fox	0.894	N/A	148	R 39,529
	19kV SWER Mink	0.549	N/A	209	R 50,124
	19kV SWER Hare	0.344	N/A	292	R 61,027
22kV Phase-to-phase Squirrel 22kV Phase-to-phase Mink	22kV Phase-to-phase Squirrel	1.505	N/A	105	R 37,972
	22kV Phase-to-phase Fox	0.845	N/A	148	R 44,284
	22kV Phase-to-phase Mink	0.500	N/A	209	R 57,567
	22kV Phase-to-phase Hare	0.296	N/A	292	R 71,842
22kV Three phase Squirrel 22kV Three phase Mink	22kV Three phase Squirrel	1.505	N/A	105	R 52,190
	22kV Three phase Fox	0.845	N/A	148	R 61,117
	22kV Three phase Mink	0.500	N/A	209	R 79,850
	22kV Three phase Hare	0.296	N/A	292	R 100,115
460V Bi-phase ABC 35mm <sup>2</sup>	460V Bi-phase ABC 25mm <sup>2</sup> Al	1.297	1.065	105	R 51,255
	460V Bi-phase ABC 35mm <sup>2</sup> Al	0.938	1.065	144	R 55,638
	460V Bi-phase ABC 50mm <sup>2</sup> Al	0.693	0.778	183	R 61,689
	460V Bi-phase ABC 70mm <sup>2</sup> Al	0.479	0.778	228	R 69,850
	460V Bi-phase ABC 95mm <sup>2</sup> Al	0.346	0.778	277	R 78,573
230V Single phase Airdac 4mm <sup>2</sup> 230V Single phase Airdac 10mm <sup>2</sup> 230V Single phase ABC 25mm <sup>2</sup> 230V Single phase ABC 35mm <sup>2</sup>	230V Single phase Airdac 4mm <sup>2</sup> Cu	4.990	4.990	37	R 35,978
	230V Single phase Airdac 10mm <sup>2</sup> Cu	2.000	2.000	65	R 44,136
	230V Single phase ABC 25mm <sup>2</sup> Al	1.297	1.065	105	R 44,042
	230V Single phase ABC 35mm <sup>2</sup> Al	0.938	1.065	144	R 47,746
	230V Single phase ABC 50mm <sup>2</sup> Al	0.693	0.778	183	R 53,133
	230V Single phase ABC 70mm <sup>2</sup> Al	0.479	0.778	228	R 62,904
	230V Single phase ABC 95mm <sup>2</sup> Al	0.346	0.778	277	R 69,645

Table 15.1.5: Conductor sizes used in conductor size optimisation. Rp+ve and Rn are the phase and neutral conductor resistances respectively

The network results for the optimised conductor sizes are summarised in table 15.1.6. The following should be noted:

- Compared to the original conductor sizes, the optimised conductor sizes are smaller and result in increased lifetime load loss and voltage drop cost (51.13% to 109.85% increase in load loss and voltage drop cost depending on load voltage dependency). A net lifetime cost saving of between 6.92% and 10.54% is however achieved due to a 10.33% to 12.38% reduction in conductor capital cost.
- The optimised conductor lifetime load loss and voltage drop cost represents between 3.64% and 9.88% of the conductor capital cost. The results indicate that rural electrification network planning and design is expected to be sensitive to capital cost. Lifetime costs due to conductor load losses and voltage drop are comparatively small.
- The minimum year 7 LV voltages (associated with the optimum conductor sizes) vary between 66.55% and 87.15%, and are below the 230V-10% limit prescribed by the NRS048-2 [2004]. The minimum year 15 LV voltage is between 54.91% and 81.27%.

The minimum LV voltages are sensitive to the optimal conductor sizes, which are in turn sensitive to the load voltage dependency.

Parameter	Energy and demand voltage dependency				
	K=0	K=0.5	K=1	K=1.5	K=2
Lifetime conductor active load loss energy [MWh]	4448	4232	3804	3535	3251
Lifetime conductor reactive load loss energy [MVArh]	439	445	442	449	455
Lifetime conductor active load loss energy and voltage drop cost [Rand]	R 383,722	R 656,482	R 851,994	R 1,035,477	R 1,176,006
Lifetime conductor reactive load loss energy cost [Rand]	R 341	R 345	R 343	R 348	R 354
Lifetime conductor load loss demand cost [Rand]	R 31,394	R 14,934	R 0	-R 12,277	-R 22,818
Lifetime conductor load loss energy, voltage drop and demand cost [Rand]	R 415,456	R 671,761	R 852,337	R 1,023,548	R 1,153,541
Change in lifetime conductor load loss energy, voltage drop and demand cost due to conductor size optimisation [%]	109.85%	97.98%	77.34%	64.57%	51.13%
Conductor capital cost [Rand]	R 11,409,593	R 11,434,904	R 11,513,743	R 11,576,809	R 11,676,360
Change in conductor capital cost due to conductor size optimisation [%]	-12.38%	-12.18%	-11.58%	-11.09%	-10.33%
Lifetime conductor capital and load loss energy, voltage drop and demand cost [Rand]	R 11,825,049	R 12,106,665	R 12,366,080	R 12,600,357	R 12,829,901
Lifetime conductor load loss and voltage drop cost as a % of conductor capital cost [%]	3.64%	5.87%	7.40%	8.84%	9.88%
Change in lifetime conductor capital, load loss energy, voltage drop and demand cost due to conductor size optimisation [%]	-10.54%	-9.38%	-8.41%	-7.64%	-6.92%
Minimum MV voltage in year 7 [%]	96.07%	96.07%	96.73%	96.73%	96.73%
Minimum LV voltage in year 7 [%]	66.55%	75.86%	87.15%	87.15%	87.15%
Minimum MV voltage in year 15 [%]	93.93%	93.93%	94.78%	94.78%	94.78%
Minimum LV voltage in year 15 [%]	54.91%	66.84%	81.27%	81.27%	81.27%

Table 15.1.6: Sample rural domestic electrification network results  
(optimised conductor sizes)

## 15.2 OBSERVATIONS BASED ON THE SAMPLE NETWORK ANALYSIS

The following observations can be made based on the sample rural domestic electrification network results:

- Conductor lifetime reactive load loss energy costs are less than 0.1% of the conductor lifetime active load loss energy, voltage drop and demand costs. Reactive load loss energy costs can be ignored for South African distribution conductor size optimisation without significantly compromising accuracy (raised in section 5.3.1).
- Changes in consumer energy consumption and demand (due to conductor voltage drop and load voltage dependency) significantly effect conductor lifetime costs and optimal conductor sizes (raised in section 3.2).

- In rural domestic electrification networks the minimum LV voltages associated with the optimum conductor sizes may be significantly lower than the limits allowed in present South African standards, specifically the NRS048-2 [2004]. This supports the finding of Sellick [1999].
- The consideration of conductor technical losses and changes in consumer energy consumption and demand due to conductor voltage drop and load voltage dependency do not significantly affect South African rural domestic electrification conductor size selection as the conductor sizes are dictated by minimum voltage limits. Given present voltage limits, the philosophy of minimum initial capital cost appears to be appropriate for conductor sizing in South African rural domestic electrification (raised in section 1.3).
- If the minimum voltage limit is ignored the net lifetime cost savings for the sample South African rural domestic electrification network is between 6.92% and 10.54%. The potential savings (as compared to designs based on voltage limits) compare favourably with the typical reduction in lifetime cost of between 9% and 11% calculated by Sellick [1999]. A 5% conductor lifetime cost saving in the South African electrification program (with an expected initial capital cost of at least R10billion) is expected to save R360million.
- The sample network year 15 minimum LV voltages associated with the optimal conductor sizes vary between 54.91% and 81.27%. Further research into a possible reduction of the minimum voltage limit for South African rural domestic electrification should be performed and would need to assess impacts on consumer appliances and establish the extent to which reduced voltages reduce the benefit of electricity to the poor.

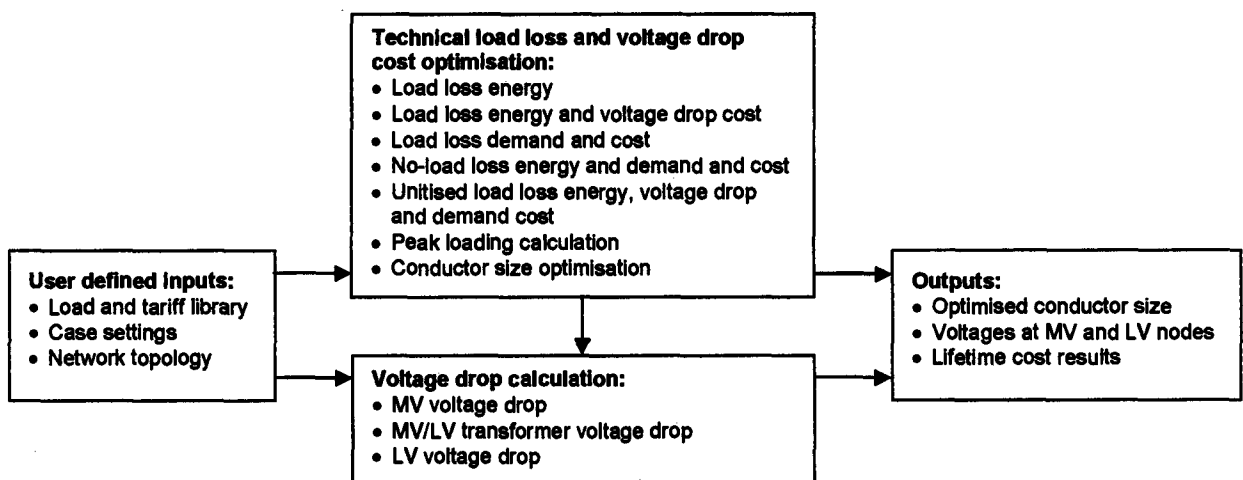
## 16. SUMMARY AND CONCLUSION

### 16.1 A NEW METHOD FOR DISTRIBUTION NETWORK CONDUCTOR SIZE OPTIMISATION

#### 16.1.1 Overview of the new method

A new conductor size optimisation method has been developed for radial distribution networks and is summarised in figure 16.1.1.1. The technical load loss cost optimisation and voltage drop calculation uses the same network and load data. The optimised conductor size (as performed in the technical load loss cost optimisation) is an input to the voltage drop calculation.

Figure 16.1.1.1: Overview of the new method for distribution conductor size optimisation and voltage drop calculation



The method has the following main features considered appropriate for the optimisation of conductor sizes and calculation of voltage drops in South African domestic electrification networks:

- It applies to radial MV and LV balanced and unbalanced network technologies and loads.
- Load classes are described by Load Groups with daily load profiles for each day type in each season. Future load changes are described by Load Group annual energy and demand load forecasts.
- The stochastic nature of the loads is modelled using parameters describing both the mean and variance of the loads.
- Fixed and variable loads (with different load shapes, power factors and load forecasts) can be combined in the same network study.
- The network topology is user defined and is constant for the evaluation period. The user defined network topology includes network connectivity, line lengths, voltage levels and technologies.

The following applies to the technical load loss and voltage drop cost optimisation:

- Load losses are calculated in each time interval of each day type in each season. The effect of load balancing (at peak loading and other time periods) is modelled.
- Load loss energy and demand calculations are based on constant current load models. The likely errors for loads that are not constant current have been shown to be relatively small.
- Load power factor is modelled.
- The calculations are performed separately for each phase/neutral conductor. Neutral conductor losses are explicitly calculated.
- Active load loss energy costs are based on the time-of-use Utility Loss Tariff, Customer Tariffs and consumer energy voltage dependency. The load loss energy costs for each conductor incorporates the missed opportunity cost due to changes in downstream consumer energy consumption as a result of conductor voltage drop.
- Load loss demand costing is performed for a user defined time and day type. The diversity of the load loss demand with upstream network/generation loading is explicitly modelled.
- Active load loss demand costs are based on the Utility Loss Tariff demand charge and consumer demand voltage dependency. The load loss demand costs for each conductor incorporates changes in downstream consumer demand as a result of the conductor voltage drop. It is assumed that customers do not pay demand charges.

- Reactive load and no-load loss energy costs are based on switched and fixed shunt capacitor lifetime costs respectively.
- The lifetime energy, voltage drop and demand costs are expressed as a Net Present Value using the evaluation period, Load Group load forecasts, Utility Loss Tariff forecasts, Customer Tariff forecast and Net Discount Rate.
- No-load losses, shunt capacitors, transformers, and DETS tap settings are accounted for in the calculations.
- The conductor size in each branch is optimised to minimise the sum of the branch capital and lifetime technical loss and voltage drop costs (incorporates changes in consumer energy consumption and demand as a result of load voltage dependency and conductor voltage drop). The conductor optimisation is constrained by conductor thermal ratings. Common costs such as operating and maintenance, pole top boxes, kiosks and meters are ignored as they are considered to be independent of conductor size.
- The level of non-technical losses is taken into consideration via the Revenue Recovery Rate, which changes the effective cost of conductor load losses for loads that are not constant power.
- A forecast limit can be applied to account for future network upgrades/additions.
- Loss analysis results are calculated for each branch.

Voltages at MV and LV nodes are calculated for a user defined percentile and confidence level using the following features and assumptions:

- LV voltage drop is calculated using the QOS voltage drop calculation method developed by Heunis [2000]. The QOS method has been enhanced to improve accuracy when applied to shorter time intervals such as 1 hour. The calculations are based on a constant current load model, unity load power factor and ignore network reactance. The resultant error due to these simplifications has been shown to be small.
- MV/LV transformer voltage drop is calculated using the MV/LV transformer load calculated using the QOS load model (as used in the LV voltage drop calculation). The calculations are based on a constant current load model. The resultant errors for loads that are not constant current have been shown to be small.
- MV network voltage drop is calculated using deterministic load-flow. The MV/LV transformer loads are modelled as “bulk” loads at the MV terminals of each MV/LV distribution transformers. The MV bulk load at each transformer is based on the normalised load mean and variance for the number of customers supplied by the entire MV network multiplied by the number of consumers supplied by that MV/LV transformer.

- Load power factor and reactance are included in the MV/LV transformer and MV network voltage drop calculations as it has been shown that unity power factor assumptions and ignoring network reactance result in unacceptably large errors for MV/LV transformer and MV network voltage drop calculation.

The optimised conductor size is the economic size at which the conductor capital cost and lifetime cost of technical losses (including the effect of load voltage dependency and conductor voltage drop on utility bulk energy purchase costs and utility revenue) is minimised for a set of conductors.

The voltages calculated at each MV and LV node are based on the optimised conductor size and account for the stochastic load variation of individual consumers and risk. Conductor optimisation is not constrained by a maximum voltage drop limit or minimum voltage limit.

By manipulating the network topology, the method can also be used to enhance other network planning and design optimisation problems, such as the selection of line technology (three phase, single phase, phase-to-phase, bi-phase, SWER) and voltage level.

#### 16.1.2 Method testing to determine accuracy

The components of the method (load losses, load loss and voltage drop cost, MV voltage drop and LV voltage drop calculations) have been tested. Two categories of tests were performed:

- Sensitivity analysis on case networks: Simplifications and assumptions are made in the calculations. Examples include the use of constant current load models, and ignoring network reactance and assuming unity power factor for LV voltage drop assessment. The sensitivity of the results and likely error range associated with these simplifications and assumptions were established via the analysis of case networks. The results verify the validity of the simplifications and assumptions for application in South African networks.
- Monte Carlo simulation: 5 minute average currents samples (date and time stamped) are recorded for selected customers in projects representing (as far a possible) the range of domestic customers in South Africa. Monte Carlo simulation performed using this load research data verifies the accuracy of the statistical and probabilistic load models used in the load loss and voltage drop calculations.

### 16.1.3 Comparison with traditional methods to determine relevance

The historical conductor size optimisation methods as developed by IEC 287-3-2 [1995], Willis [1997], Sellick [1999], Curcic et al [2001], Mandal and Pahwa [2002] and Falaghi et al [2005] require a reasonably accurate assessment of the cost of conductor load losses. The proposed method can be compared with existing methods via comparison of the costs of load losses calculated using the different methods.

#### Load loss energy and load loss energy cost

The results of the calculated and Monte Carlo simulated values of load loss energy and load loss energy cost were compared for three NRS034-1 [1999] LV networks. Three methods were tested:

- Loss Load Factor (LLF) with load-flow at peak loading: The average energy load loss is estimated based on the load losses at peak (from load-flow) and an empirical relationship between the peak loss, average losses and Load Factor.
- Average profile load-flow: Energy losses are calculated via load-flow analysis in 1 hour time intervals using mean daily load profiles. The variance of the load within 1 hour time intervals is ignored.
- The proposed method: As developed in this research.

In the LV case networks supplying South African domestic consumers the traditional Loss Load Factor and average profile load-flow methods understate the load loss energy and load loss energy cost by up to 41.2% and 55.7% respectively. The errors in these empirical calculations are large.

The errors in the proposed method are small (<2.7%) and within practical planning and design requirements.

## Effective cost of load losses incorporating conductor voltage drop and load voltage dependency

The consideration of consumer load voltage dependency has identified the following significant implications for conductor size optimisation in passive distribution networks:

- Load loss magnitude and voltage drop do not vary significantly with load voltage dependency. Constant current models are appropriate for the calculation of distribution network load losses and voltage drops.
- The effect of load losses on utility bulk energy purchases varies with load voltage dependency. Load losses do not necessarily increase utility bulk energy purchases. Increased load loss in networks supplying constant impedance loads reduces total system loading.
- Conductor voltage drop affects consumer energy consumption and demand (and hence utility revenue) for loads that are not constant power.
- Load losses, changes in utility bulk energy purchase costs and changes in utility revenue are related, are influenced by load voltage dependency and can not be considered in isolation.

In traditional conductor size optimisation methods technical load loss costs are only based on upstream generation and network costs. These loss costing methods assume that consumers behave as constant power loads. The impact of changes in consumer energy consumption and demand (due to conductor voltage drop and load voltage dependency) on utility bulk energy purchase cost and utility revenue are ignored. For consumers that are not constant power the Loss Load Factor and average profile load-flow methods used with traditional load loss costing methods may account for less than 25% (for the case network tested) of the conductor load loss energy and voltage drop cost.

In the new method an approximate relationship between load losses, change in consumer energy consumption and demand, and load voltage dependency is used to calculate the effective cost of conductor load loss energy and load loss demand incorporating the effects of load voltage dependency and conductor voltage drop. The errors in the new method are small (typically between 3% and -4% for moderate variations from constant current loads  $K = 0.5$  to  $1.5$ ) and are within practical planning and design requirements.

#### 16.1.4 Implications for network planning and design

Comparison of the new method and previous methods indicates that historical distribution network conductor size optimisation methods understate the magnitude and cost of load losses in LV networks supplying stochastic domestic loads. Application of the new method in thermally limited networks (typically supplying domestic consumers with average monthly consumption greater than 500kWh) may result in the selection of larger optimal conductor sizes (increased capital cost) and reduced voltage variation as compared to historical practices.

Conductor size affects consumer energy consumption due to conductor voltage drop and load voltage dependency. Non-technical losses are expected to vary with conductor size for loads that are not constant power. This may have significant implications for planning and design, as larger conductor sizes may support increased non-technical losses in networks with high levels of electricity theft. Non-technical losses can not be considered to be independent of conductor size, and this is a point of departure from previous conductor size optimisation methods.

As demonstrated in chapter 15, the capacity of South African rural domestic electrification networks are constrained by present voltage limits. The lifetime cost of conductor load loss and voltage drop is significantly less than the conductor capital cost. This is not surprising as the customers have very low monthly energy consumption and a low load factor. The optimum conductor sizes (minimising capital and lifetime loss and voltage drop costs) result in consumer LV voltages below the South African limit of 400//230V -10% as prescribed in the NRS 048-2 [2004]. The results indicate that a reduction in minimum voltage limits for rural electrification consumers may reduce lifetime cost. The implications for consumer appliances would need to be assessed.

#### 16.1.5 Scope for further enhancements

##### Distributed Generation (DG)

As discussed in section 2.5, it would be beneficial if the method developed by this research could consider DG (or be enhanced to consider DG) thereby also being applicable in applications where significant DG penetration levels are expected.

The load loss calculations can model DG as negative loads (180 degree phase shift relative to conventional loads) using a constant current DG model. DG would be represented by profiles of mean and variance for each time interval, day type and season.

The QOS load model and its associated beta distribution used in the voltage drop calculations would need to be investigated further to assess the impact of the modelling of DG.

### Additional constraints

The conductor size optimisation is constrained by conductor thermal rating. It is not constrained by fault level ratings or a minimum voltage requirement.

As per IEC 287-3-2 [1995] and Sellick [1999], the optimised economic conductor size is a minimum conductor size. Additional constraints (such as fault level rating as may need to be assessed in other countries/networks) could be included as additional steps following the economic conductor size optimisation.

A minimum voltage requirement could be implemented by incorporating the new method developed by this research with an iterative conductor optimisation routine such as described by Falaghi et al [2005].

## 16.2 ASSESSING THE RESEARCH NOVELTY AND HYPOTHESIS

The conductor size optimisation method developed by this research improves on previous methods and includes several novel features. For example:

- Load models are based on load profile uncertainty and account for the stochastic nature of individual loads for both load loss and voltage drop calculations. The dynamic nature of the load diversity and unbalance is modelled.
- Load loss and voltage drop calculations use the same load models. This enables load loss and voltage drop calculation in the same study.
- Probabilistic voltage drop calculations are used with a user defined percentile and confidence level. Risk in voltage drop calculations is accounted for.
- The cost of load losses supports time-of-use Utility Loss Tariffs, and accounts for generation/transmission costs during different times of the day, days of the week and seasons of the year.

- Different consumer load classes (with different load shapes and load forecasts) can be accurately mixed in the same study.
- The effect of load voltage dependency and conductor voltage drop on customer energy consumption and demand is accounted for, such that conductor load loss costs incorporate changes in utility bulk energy purchase costs and changes in utility revenue.
- Both the MV and LV networks can be analysed in the same network study, thereby avoiding sub-optimisation between MV and LV network levels. The full range of balanced and unbalanced network technologies and voltage levels in South Africa is supported.

The simplifications and assumptions used in the method have been tested via sensitivity analysis on South African domestic electrification networks. The accuracy of the load loss and voltage drop calculations used in the method have been tested via Monte Carlo simulation using South African domestic load research data. The method has been implemented in network analysis software such that it can be used in practical planning and design functions in utilities.

The errors in previous methods for the calculation and costing of conductor load losses have been shown to be large in LV networks supplying stochastic domestic loads.

The hypothesis for this research was that:

*It is possible to optimise conductor size for a wide range of electrification network voltage levels and technologies used in South Africa, but with a practical level of detail so that the approach could be used in planning and design functions in the South African utilities and in other countries.*

It is not possible to prove conductor size optimisation due to other factors that could affect conductor size and have not been taken into consideration. The hypothesis can not be validated in its present form. The hypothesis can be validated in the following revised form:

**It is possible to improve conductor size optimisation for a wide range of electrification network voltage levels and technologies used in South Africa, but with a practical level of detail so that the approach could be used in planning and design functions in the South African utilities and in other countries.**

Comparing the proposed method with previous methods it can be concluded that it is possible to improve conductor optimisation by combining MV and LV network analysis to

prevent sub-optimisation, using statistical time-of-use technical load loss and voltage drop calculations that consider the stochastic nature of individual loads, and by considering the effect of changes in consumer energy consumption and demand (due to load voltage dependency and conductor voltage drop) on utility bulk energy purchase cost and utility revenue.

### 16.3 RELEVANCE OF THE RESEARCH

The method should be appropriate for the optimisation of MV and LV conductor sizes in most developing countries.

Application of the method in the South African domestic electrification program may result in significant lifetime cost savings thereby facilitating electrification and enhancing the lives of millions of South Africans.

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# LIST OF SYMBOLS

## Chapter 5

$\sigma$	Standard deviation of the current [amps]
$\rho_{ij}$	Correlation between the load currents of consumers i and j
$\sigma_k$	Standard deviation of the load current of consumer k [amps]
$\mu$	Average value of the current [amps]
$\mu_k$	Average value of the load current of consumer k [amps]
Avg demand	Average load demand in time period [kW]
Avg load loss	Average load loss in time period [kW]
$E[I^2]$	Expected value of the second moment of the current [amps <sup>2</sup> ]
Eval period	Time in evaluation period [hours]
LF	Ratio of the average demand to the maximum demand (within a period)
LLF	Loss Load Factor [per-unit]
Load loss energy	Load loss energy over evaluation period [kWh]
Loss	Load loss [W]
Max demand	Maximum load demand in time period [kW]
Max load loss	Maximum load loss in time period [kW]
N	Number of consumers
R	Resistance [ $\Omega$ ]
X	A constant dependent on the load characteristic, and is derived empirically
$\alpha$	A constant that typically varies between 1.55 and 1.80

## Chapter 10

CLLD	Cost of technical load loss demand incorporating voltage drop and load voltage dependency [Rand/kW]
CLLE	Cost of technical load loss energy incorporating voltage drop and load voltage dependency [Rand/kWh]
$CT_{ad}$	Customer Tariff active demand charge [Rand/kW]
$CT_{ae}$	Customer Tariff active energy charge [Rand/kWh]
DNP	Decrease in Net Profit due to technical load loss and reduction in revenue [Rand]
$E_b$	Customer base energy consumption assuming zero voltage variation [kWh]

$E_v$	Reduction in customer energy consumption due to voltage variation [kWh]
$K_d$	Per-unit change in customer active power demand for a per-unit change in voltage [ratio]
$K_e$	Per-unit change in customer active energy consumption for a per-unit change in voltage [ratio]
$L_{ne}$	Network technical loss energy [kWh]
$L_{neL}$	Network technical load loss energy [kWh]
NP	Net Profit [Rand]
RRR	Revenue Recovery Rate [per-unit]
$ULT_{ad}$	Utility Loss Tariff active demand charge [Rand/kW]
$ULT_{ae}$	Utility Loss Tariff active energy charge [Rand/kWh]

## Chapter 11

$\sigma_i^2$	Variance of the load current of consumer i [amps <sup>2</sup> ]
$\sigma_j, \sigma_k$	Standard deviation of the load current of consumers j and k [amps]
$\rho_{jk}$	Correlation between the load currents of consumers j and k
$\mu_T$	Conductor current mean [amps]
$\sigma_T$	Conductor current standard deviation [amps]
$\mu_i$	Average value of the load current of consumer i [amps]
$A_i, A_j, A_k$	Phase angle of Load Bin i, j and k currents respectively [degrees]
Avg Loss	Average load loss active power [W]
$E[\mu]$	Average of the load current signal means [amps]
$E[\sigma]$	Average of the load current signal standard deviations [amps]
$E[\rho]$	Average of the correlation of load current signals [unitless]
$E[\sigma^2]$	Average of the load current signal variances [amps <sup>2</sup> ]
$E[\rho_{jk}]$	Average of the correlation of current signals between Load Bins j and k [unitless]
$E[\sigma_i^2]$	Average of the Load Bin i current signal variances [amps <sup>2</sup> ]
$E[\mu_i]$	Average of the Load Bin i current signal means [amps]
$E[\rho_i]$	Average of the correlation of Load Bin i current signals [unitless]
$E[\sigma_i], E[\sigma_j], E[\sigma_k]$	Average of the Load Bin i, j and k current signal standard deviations respectively [amps]
LB	Number of Load Bins
$N_i, N_j, N_k$	Number of consumers in Load Bin i, j and k respectively
SF	Scaling factor [per-unit]

$SF_i, SF_j$	Scaling factor of consumers i and j [per-unit]
$SF_l, SF_j, SF_k$	Scaling factor of Load Bin l, j and k respectively
$V[\mu]$	Variance of the mean values of the load current signal [amps <sup>2</sup> ]
$V[\mu_l]$	Variance of the Load Bin l mean values of the current signal [amps <sup>2</sup> ]

## A. APPENDIX A: ERROR IN SELICK LOSS CALCULATION

Consider a single phase 230V branch supplying 1, 3, 5, 10, 20 or 50 domestic customers with the peak load characteristics in table A.1. The average 5 minute load loss at peak was calculated via equations 11.1.2.1, 11.1.2.2 and 11.1.2.3 assuming zero correlation between consumer currents (consumer currents within a 5 minute time period are considered to be uncorrelated [Heunis, 2000]). The error in this calculation is expected to be less than 2% (see section 11.2.2). The average load loss at peak was also calculated based on the Herman Beta current with a 50% confidence level as per Sellick [1999].

Community	Average current at peak [amps]	Standard deviation of current at peak [amps]	Coefficient of variation of current at peak [ratio]	Herman Beta: Alpha	Herman Beta: Beta	Herman Beta: Circuit Breaker rating [amps]
Antioch 2003	2.50	3.31	1.32	0.37	2.62	20
Greenturf 2003	7.06	6.00	0.85	0.96	4.50	40
Moreietta 2003	21.15	13.76	0.65	1.47	4.10	80

Table A.1: Load parameters used to test Sellick [Sellick, 1999] assumption [Dekenah, 2003]

Community	Number of customers	Average load loss at peak [kW/Ω]	Sellick load loss at peak [kW/Ω]	Error in Sellick load loss [%]
Antioch 2003	1	0.017	0.001	-93.60%
	3	0.089	0.038	-57.65%
	5	0.211	0.125	-40.75%
	10	0.735	0.562	-23.44%
	20	2.719	2.375	-12.67%
	50	16.173	15.312	-5.32%
Greenturf 2003	1	0.086	0.030	-65.20%
	3	0.557	0.390	-29.86%
	5	1.426	1.150	-19.35%
	10	5.344	4.794	-10.30%
	20	20.657	19.559	-5.32%
	50	126.409	123.664	-2.17%
Moreietta 2003	1	0.637	0.353	-44.53%
	3	4.594	3.770	-17.93%
	5	12.130	10.766	-11.24%
	10	46.626	43.911	-5.82%
	20	182.716	177.299	-2.96%
	50	1127.773	1114.250	-1.20%

Table A.2: Error in Sellick [1999] assumption that the average load loss at peak can be based on the 50<sup>th</sup> percentile Herman Beta current at peak loading

As per table A.2, the method used by Sellick [1999] significantly underestimates the average load loss at peak loading. The error increases with reducing customer numbers and increasing coefficient of variation (inaccuracies in the modelling of the current variance are more pronounced).

## B. APPENDIX B: SOUTH AFRICAN LOW-INCOME DOMESTIC CONSUMER POWER FACTORS

### B.1 ABATTOIR NB114

Parameter	Value
Network	Abattoir NB114
Customers	Low-income rural domestic
Statistical metering period	15/04/2004 to 30/09/2004
% data valid	98.86%
Peak load	3959kVA
Average power factor	0.991

Table B.1.1: Abattoir NB114 summary table

The "% data valid" refers to the percentage data that has been used after filtering for abnormal network events (as a percentage of the total number of load recordings potentially available for the metering period).

Time	Abattoir NB114											
	Weekday				Saturday				Sunday			
	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$
1:00	0.978	0.010	921	114	0.979	0.009	981	94	0.978	0.010	925	89
2:00	0.976	0.011	859	89	0.977	0.010	920	86	0.976	0.011	887	75
3:00	0.977	0.010	845	91	0.976	0.010	878	76	0.974	0.011	846	67
4:00	0.978	0.010	853	84	0.977	0.010	857	71	0.974	0.010	828	65
5:00	0.986	0.008	997	121	0.980	0.009	902	78	0.976	0.010	846	68
6:00	0.994	0.004	1572	243	0.988	0.006	1115	114	0.982	0.008	951	81
7:00	0.997	0.002	2148	334	0.992	0.004	1383	143	0.989	0.005	1204	143
8:00	0.997	0.002	2338	321	0.995	0.002	1805	186	0.994	0.002	1738	171
9:00	0.995	0.003	2081	258	0.995	0.002	2076	198	0.995	0.002	2179	180
10:00	0.993	0.004	1989	336	0.994	0.003	2000	232	0.995	0.002	2263	213
11:00	0.991	0.005	1851	357	0.991	0.004	1804	209	0.993	0.003	2118	229
12:00	0.986	0.007	1762	363	0.988	0.005	1649	201	0.991	0.004	1916	225
13:00	0.987	0.008	1702	370	0.985	0.007	1569	195	0.989	0.005	1788	234
14:00	0.986	0.008	1685	377	0.984	0.007	1551	169	0.988	0.006	1776	238
15:00	0.987	0.008	1756	379	0.984	0.007	1570	171	0.989	0.005	1807	234
16:00	0.990	0.006	1880	385	0.986	0.007	1673	229	0.990	0.005	1935	269
17:00	0.992	0.004	2133	380	0.988	0.005	1857	239	0.992	0.004	2149	304
18:00	0.995	0.003	2455	400	0.992	0.004	2207	319	0.995	0.002	2474	342
19:00	0.997	0.001	3122	362	0.996	0.001	2931	296	0.997	0.001	3087	272
20:00	0.997	0.001	3150	280	0.996	0.001	2904	212	0.997	0.001	3079	236
21:00	0.996	0.001	2696	309	0.995	0.002	2479	253	0.996	0.001	2555	281
22:00	0.994	0.003	2022	294	0.993	0.003	1912	248	0.994	0.003	1858	260
23:00	0.989	0.006	1380	229	0.988	0.006	1420	194	0.986	0.006	1316	191
24:00	0.983	0.009	1052	154	0.982	0.009	1096	120	0.982	0.008	1017	122

Table B.1.2: Abattoir NB114 power factor and apparent power (15/04/2004 to 30/09/2004)

## B.2 ABATTOIR NB115

Parameter	Value
Network	Abattoir NB115
Customers	Low-income rural domestic
Statistical metering period	15/04/2004 to 30/09/2004
% data valid	98.86%
Peak load	2353kVA
Average power factor	0.993

Table B.2.1: Abattoir NB115 summary table

Time	Abattoir NB115											
	Weekday				Saturday				Sunday			
	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$	PF $\mu$	PF $\sigma$	kVA $\mu$	kVA $\sigma$
1:00	0.987	0.006	591	50	0.987	0.006	633	45	0.988	0.006	610	40
2:00	0.986	0.007	562	39	0.987	0.006	588	42	0.988	0.006	598	36
3:00	0.986	0.007	554	37	0.987	0.006	570	38	0.989	0.006	578	34
4:00	0.987	0.006	564	38	0.986	0.006	563	36	0.990	0.006	566	33
5:00	0.988	0.006	661	66	0.990	0.005	595	41	0.993	0.004	574	34
6:00	0.990	0.005	861	92	0.993	0.004	671	47	0.996	0.003	613	35
7:00	0.994	0.003	1250	270	0.995	0.002	818	96	0.997	0.002	748	93
8:00	0.996	0.001	1526	245	0.997	0.002	1106	113	0.997	0.001	1103	132
9:00	0.996	0.001	1281	151	0.996	0.002	1267	110	0.997	0.001	1395	98
10:00	0.995	0.001	1214	181	0.995	0.002	1223	126	0.996	0.002	1421	116
11:00	0.994	0.002	1124	180	0.993	0.003	1097	102	0.995	0.003	1308	112
12:00	0.993	0.002	1043	173	0.991	0.004	997	86	0.993	0.003	1168	87
13:00	0.992	0.003	1014	169	0.989	0.005	957	82	0.992	0.004	1080	89
14:00	0.991	0.003	999	165	0.988	0.005	938	75	0.991	0.005	1058	92
15:00	0.990	0.004	994	167	0.986	0.006	921	70	0.991	0.005	1033	98
16:00	0.990	0.004	1016	169	0.986	0.007	920	94	0.991	0.005	1047	115
17:00	0.992	0.003	1093	178	0.987	0.006	952	101	0.992	0.004	1098	130
18:00	0.993	0.002	1263	217	0.990	0.005	1132	190	0.993	0.003	1270	194
19:00	0.995	0.001	1847	253	0.994	0.002	1786	248	0.995	0.001	1846	230
20:00	0.995	0.001	1941	157	0.995	0.001	1846	137	0.995	0.001	1931	152
21:00	0.995	0.001	1618	167	0.995	0.001	1561	154	0.996	0.001	1571	163
22:00	0.995	0.002	1194	149	0.994	0.002	1190	143	0.995	0.002	1130	144
23:00	0.992	0.003	833	106	0.991	0.004	897	100	0.992	0.004	812	87
24:00	0.989	0.004	658	70	0.988	0.005	714	56	0.990	0.005	652	53

Table B.2.2: Abattoir NB115 power factor and apparent power (15/04/2004 to 30/09/2004)

## C. APPENDIX C: NETWORK PARAMETER SENSITIVITY RESULTS

Parameter	PF1 Expected (0.991)			PF2 (0.98)			PF3 (0.96)		
	50%	100%	150%	50%	100%	150%	50%	100%	150%
Reactance scaling factor									
MV voltage drop [%]	5.21%	5.77%	6.52%	5.43%	6.26%	7.29%	5.62%	6.73%	8.02%
MV/LV trfr voltage drop [%]	2.93%	3.25%	3.62%	3.11%	3.61%	4.18%	3.26%	3.97%	4.74%
LV voltage drop [%]	3.77%	3.80%	3.83%	3.75%	3.81%	3.86%	3.71%	3.79%	3.87%
Sum of voltage drops [%]	11.91%	12.81%	13.97%	12.29%	13.68%	15.33%	12.59%	14.49%	16.63%
MV voltage drop error if X and PF are ignored [%]	-6.63%	-15.71%	-25.48%	-10.43%	-22.37%	-33.29%	-13.44%	-27.76%	-39.41%
MV/LV trfr voltage drop error if X and PF are ignored [%]	-8.38%	-17.21%	-25.72%	-13.44%	-25.65%	-35.75%	-17.53%	-32.31%	-43.27%
LV voltage drop error if X and PF are ignored [%]	-0.34%	-1.05%	-1.88%	0.05%	-1.31%	-2.74%	1.27%	-0.79%	-2.87%
Total voltage drop error if X and PF are ignored [%]	-5.07%	-11.75%	-19.07%	-7.99%	-17.38%	-26.27%	-10.16%	-21.96%	-32.01%

Table C.1: Error in voltage drop if reactance (X) and power factor (PF) are ignored (constant current load)

Parameter	Load voltage dependency (K)				
	0.00	0.50	1.00	1.50	2.00
MV voltage drop error assuming constant current load [%]	-2.65%	-1.27%	0.00%	1.12%	2.16%
MV/LV trfr voltage drop error assuming constant current load [%]	-4.76%	-2.28%	0.00%	2.18%	4.16%
LV voltage drop error assuming constant current load [%]	-8.20%	-3.95%	0.00%	3.69%	7.17%
Sum of voltage drop error assuming constant current load [%]	-4.89%	-2.33%	0.00%	2.14%	4.11%

Table C.2: Error in voltage drop calculation assuming a constant current load (expected power factor and reactance)

Parameter	Load voltage dependency (K)				
	0.00	0.50	1.00	1.50	2.00
Demand loss error assuming constant current load [%]	0.88%	0.37%	0.00%	-0.25%	-0.41%
Energy loss error assuming constant current load [%]	-6.08%	-3.05%	0.00%	3.06%	6.12%

Table C.3: Error in load loss energy and demand assuming a constant current load (expected power factor and reactance)

Parameter	Load voltage dependency (K)				
	0.00	0.50	1.00	1.50	2.00
Change in demand prediction error: Total network [%]	-5.99%	-5.33%	-6.63%	-8.04%	-9.50%
Change in demand prediction error: MV and LV lines [%]	5.00%	3.00%	-0.60%	-4.02%	-7.28%
Change in demand prediction error: MV/LV transformers [%]	-3.61%	-6.89%	-12.12%	-16.98%	-21.49%
Change in energy prediction error: Total network [%]	2.15%	-0.25%	-4.33%	-8.21%	-11.87%

Table C.4: Error in the prediction of the change in consumer energy consumption and demand (expected power factor and reactance)

Parameter	Reactance scaling factor		
	50%	100%	150%
Power Factor 1 Expected (0.991)	-0.21%	-0.60%	-1.15%
Power Factor 2 (0.98)	-0.23%	-2.12%	-4.10%
Power Factor 3 (0.96)	1.45%	-2.02%	-5.38%

Table C.5: Error in the estimation of the change in consumer demand for MV and LV lines (constant current load)

## D. APPENDIX D: EFFECTIVE COST OF LOAD LOSS ENERGY CASE STUDY

Load-flow results	Load voltage dependency	Conductor			
		Short circuit	70mm ABC	50mm ABC	35mm ABC
Voltage drop [%]	K=0	0.00%	2.35%	3.41%	4.69%
	K=0.5		2.33%	3.36%	4.59%
	K=1		2.31%	3.31%	4.50%
	K=1.5		2.30%	3.27%	4.41%
	K=2		2.28%	3.22%	4.32%
Maximum weekday load (both customer load and load losses) [kW]	K=0	29.91	30.56	30.80	31.15
	K=0.5		30.23	30.34	30.51
	K=1		29.91	29.91	29.91
	K=1.5		29.60	29.50	29.35
	K=2		29.30	29.10	28.84
Weekday technical load loss energy [kWh]	K=0	0.00	5.71	7.77	10.75
	K=0.5		5.60	7.56	10.35
	K=1		5.49	7.37	9.99
	K=1.5		5.39	7.18	9.65
	K=2		5.29	7.01	9.34
Weekday customer load energy consumption [kWh]	K=0	408.35	408.35	408.35	408.35
	K=0.5		405.55	404.59	403.23
	K=1		402.83	400.98	398.39
	K=1.5		400.19	397.51	393.79
	K=2		397.62	394.15	389.41

Table D.1: Case study network load-flow results  
 ("short circuit" refers to an ideal branch conductor with zero impedance)

Cost parameter	Load volt dependency	Low Season				High Season			
		Conductor				Conductor			
		Short circuit	70mm ABC	50mm ABC	35mm ABC	Short circuit	70mm ABC	50mm ABC	35mm ABC
Utility monthly weekday energy purchase cost [Rand]	K=0	R 887	R 900	R 905	R 912	R 2,153	R 2,188	R 2,201	R 2,220
	K=0.5		R 893	R 896	R 899		R 2,170	R 2,177	R 2,185
	K=1		R 887	R 887	R 887		R 2,153	R 2,153	R 2,153
	K=1.5		R 880	R 878	R 875		R 2,136	R 2,131	R 2,123
	K=2		R 874	R 870	R 865		R 2,120	R 2,109	R 2,094
Customer monthly weekday energy revenue [Rand]	K=0	R 3,488	R 3,488	R 3,488	R 3,488	R 3,488	R 3,488	R 3,488	R 3,488
	K=0.5		R 3,465	R 3,456	R 3,445		R 3,465	R 3,456	R 3,445
	K=1		R 3,441	R 3,426	R 3,403		R 3,441	R 3,426	R 3,403
	K=1.5		R 3,419	R 3,396	R 3,364		R 3,419	R 3,396	R 3,364
	K=2		R 3,397	R 3,367	R 3,327		R 3,397	R 3,367	R 3,327
Utility monthly demand cost [Rand]	K=0	R 78	R 79	R 80	R 81	R 78	R 79	R 80	R 81
	K=0.5		R 79	R 79	R 79		R 79	R 79	R 79
	K=1		R 78	R 78	R 78		R 78	R 78	R 78
	K=1.5		R 77	R 77	R 76		R 77	R 77	R 76
	K=2		R 76	R 76	R 75		R 76	R 76	R 75
Net monthly weekday cost of load loss energy and demand (technical load loss and change in revenue) [Rand]	K=0	R 0	R 15	R 21	R 28	R 0	R 37	R 50	R 70
	K=0.5		R 31	R 42	R 58		R 42	R 57	R 78
	K=1		R 47	R 63	R 85		R 47	R 63	R 85
	K=1.5		R 62	R 831	R 112		R 52	R 69	R 93
	K=2		R 77	R 102	R 137		R 57	R 75	R 100
Cost per kWh of weekday technical load loss energy (including the effect of the change in revenue) [Rand/kWh]	K=0	N/A	R 0.13	R 0.13	R 0.13	N/A	R 0.31	R 0.31	R 0.31
	K=0.5		R 0.27	R 0.27	R 0.26		R 0.36	R 0.36	R 0.36
	K=1		R 0.41	R 0.41	R 0.41		R 0.41	R 0.41	R 0.41
	K=1.5		R 0.55	R 0.55	R 0.55		R 0.46	R 0.46	R 0.46
	K=2		R 0.70	R 0.70	R 0.70		R 0.51	R 0.51	R 0.51
Error in cost of monthly weekday load loss energy and demand assuming constant power loads and ignoring changes in revenue [%]	K=0	N/A	0.00%	0.00%	0.00%	N/A	0.00%	0.00%	0.00%
	K=0.5		-51.85%	-51.28%	-50.60%		-11.99%	-11.13%	-9.94%
	K=1		-67.99%	-67.39%	-66.63%		-21.31%	-19.94%	-18.01%
	K=1.5		-75.87%	-75.28%	-74.52%		-28.78%	-27.08%	-24.70%
	K=2		-80.54%	-79.97%	-79.21%		-34.91%	-33.00%	-30.33%
Estimated cost of monthly weekday load loss energy and demand (proposed method) [Rand]	K=0	N/A	R 14	R 19	R 26	N/A	R 35	R 47	R 64
	K=0.5		R 31	R 41	R 56		R 41	R 55	R 75
	K=1		R 47	R 63	R 85		R 47	R 63	R 85
	K=1.5		R 63	R 85	R 115		R 53	R 71	R 96
	K=2		R 79	R 107	R 145		R 59	R 79	R 107
Error in estimated cost of monthly weekday load loss energy and demand (proposed method) [%]	K=0	N/A	-4.37%	-5.79%	-7.75%	N/A	-4.48%	-5.96%	-8.07%
	K=0.5		-2.02%	-2.33%	-3.02%		-2.05%	-2.62%	-3.55%
	K=1		-0.34%	0.01%	0.23%		-0.02%	0.15%	0.26%
	K=1.5		1.18%	2.07%	3.06%		1.73%	2.53%	3.51%
	K=2		2.59%	4.00%	5.70%		3.24%	4.60%	6.35%

Table D.2: Case study cost evaluation results (100% revenue recovery)

# E. APPENDIX E: LOSS CALCULATION AND COSTING DETAIL

## E.1 LOAD, TARIFF AND FINANCIAL DATA

### E.1.1 Profile time periods (load model and Utility Loss Tariff)

The following terminology is used:

t	Time of day (e.g. 18:00)
d	Type of day (e.g. weekday, Saturday or Sunday)
s	Season of year
y	Year

The structure of the time-of-use load model and Utility Loss Tariff is described by:

i	Time interval period (e.g. 1 hour) [hours]
DT	Number of day types (e.g. 3 for weekdays, Saturdays and Sundays)
$D_{ds}$	Number of days of day type d in season s
S	Number of seasons in the year

### E.1.2 Load data

The following parameters are specified for each consumer Load Group (these parameters apply for all time intervals):

$ELV_L$	Energy voltage dependency of Load Group L [ratio]
$DLV_L$	Demand voltage dependency of Load Group L [ratio]
$SF_L$	Scaling factor of Load Group L [ratio]
$C_L$	Customer circuit breaker rating of Load Group L [amps]
$LT_L$	Customer Tariff active energy charge for Load Group L in year 1 [Rand/kWh]
$LR_L$	Customer Tariff Revenue Recovery Rate for Load Group L [per-unit]

Note: The Customer Tariff is a single part fixed energy charge with no time-of-use energy charges or demand charges.

The following time-of-use load parameters are specified for each consumer Load Group:

$E[\mu_{L,t,d,s}]$	Average of the Load Group L load means in time interval t, day type d, and season s in year 1 [kVA]
$PF_{L,t,d,s}$	Power factor of Load Group L in time interval t, day type d, and season s in year 1 [ratio]
$V[\mu_{L,t,d,s}]$	Variance of the Load Group L mean in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]
$E[\sigma^2_{L,t,d,s}]$	Average of the Load Group L variances in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]
$E[\rho_{L,t,d,s}]$	Average of the Load Group L correlation in time interval t, day type d, and season s in year 1 [unitless]
$E[\sigma_{L,t,d,s}]$	Average of the Load Group L standard deviations in time interval t, day type d, and season s in year 1 [kVA]
$G0_{L,t,d,s}$	Slope of linear regression between the standard deviation and mean of Load Group L in time interval t, day type d, and season s in year 1 [unitless]
$Ve0_{L,t,d,s}$	Square of the standard error of linear regression between the standard deviation and mean of Load Group L in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]
$G1_{L,t,d,s}$	Slope of linear regression between the variance and mean of Load Group L in time interval t, day type d, and season s in year 1 [unitless]
$Ve1_{L,t,d,s}$	Square of the standard error of linear regression between the variance and mean of Load Group L in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]

Note that  $G0_{L,t,d,s}$ ,  $Ve0_{L,t,d,s}$ ,  $G1_{L,t,d,s}$ ,  $Ve1_{L,t,d,s}$  are only required for the QOS voltage drop calculation, but are included here for completeness.

The following load forecast parameters are specified for each consumer Load Group for each future year y:

$F_{Ly}$	Per-unit increase in Load Group L energy in year y relative to year 1 [per-unit]
$FD_{Ly}$	Per-unit increase in Load Group L demand in year y relative to year 1 [per-unit]

### E.1.3 Utility Loss Tariffs

The following Utility Loss Tariff parameters are specified:

$REC_{load}$	Load reactive energy charge in year 1 [Rand/kVArh]
$REC_{no-load}$	No-load reactive energy charge in year 1 [Rand/kVArh]
$EC_{t,d,s}$	Active energy charge in time interval t, day type d and season s in year 1 [Rand/kWh]
$DC_s$	Apparent demand charge in season s in year 1 [Rand/kVA]
$PU EC_y$	Per-unit increase in energy charge in year y relative to year 1 [per-unit]. Real increase (excluding general inflation)
$PU DC_y$	Per-unit increase in demand charge in year y relative to year 1 [per-unit]. Real increase (excluding general inflation)

### E.1.4 Financial parameters

The following financial parameters are specified:

$NDR_y$	Net Discount Rate in year y [per-unit]
$PU LT_y$	Per-unit increase in Customer Tariff energy charge in year y relative to year 1 [per-unit]. Real increase (excluding general inflation)

## E.2 NETWORK TOPOLOGY AND SETUP

### E.2.1 Case study settings

The following settings are specified for a network study:

E	Evaluation period [years]
U	Forecast limit [years]
NLLPF	Transformer default no-load loss power factor [ratio]
TLV	Voltage dependency for no-load losses [ratio]
CLV	Voltage dependency for shunt capacitors [ratio]
PDD	Day type of system peak demand
PDT	Time of system peak demand
PDS	Number of standard deviations for peak loading calculation
PDY	Load year for peak loading calculation

### E.2.2 Network data

The following are specified:

- Branch line lengths, nominal voltages, connection phasing and cable/line options (for conductor size optimisation).
- Transformer impedances, nominal primary and secondary voltages, no-load losses and tap settings.

### E.2.3 Load data

Loads are modelled as Fixed Loads and Load Groups. The following are specified for each Fixed Load:

$F_f$	Magnitude of Fixed Load $f$ [kVA]
$FS_f$	Scaling factor of Fixed Load $f$ [per-unit]
$FPF_f$	Power factor of Fixed Load $f$ [ratio]
$FELV_f$	Energy voltage dependency of Fixed Load $f$ [ratio]
$FDLV_f$	Demand voltage dependency of Fixed Load $f$ [ratio]
$FLT_f$	Customer Tariff energy charge of Fixed Load $f$ in year 1 [Rand/kWh]
$FLR_f$	Customer Tariff Revenue Recovery Rate of Fixed Load $f$ [per-unit]

The load connection phasing is also specified.

The following are specified for each Load Group connected at a node:

- Load Group
- Number of consumers
- Load connection phasing

The detailed load parameters are specified by the Load Group (section E.1.2).

#### E.2.4 Transformer no-load loss modelling

Transformer no-load losses are modelled as Fixed Loads connected to the appropriate phases on the transformer primary, where:

$F_{fT}$	Magnitude of no-load Fixed Load f of transformer T [kVA]
$FPF_{fT}$	Power factor of no-load Fixed Load f of transformer T [ratio]
$FELV_{fT} = TLV$	Energy voltage dependency of no-load Fixed Load f of transformer T [ratio]
$FDLV_{fT} = TLV$	Demand voltage dependency of no-load Fixed Load f of transformer T [ratio]
$FLT_{fT}=0$	Tariff rate of no-load Fixed Load f of transformer T [Rand/kWh]

$$F_{fT} = \frac{NLL_T}{KPP_T} \quad E.2.4.1$$

$NLL_T$	No-load loss apparent power of transformer T [kVA] (for all phases)
$KPP_T$	Number of primary phases of transformer T. See table E.3.1.3.

If the transformer no-load loss power factor is not specified then  $FPF_{fT} = NLLPF$ .

The number of fixed loads modelled per transformer is equal to the number of primary phases on each transformer (transformer losses are modelled as balanced single phase loads). The number and phasing of the fixed loads for each transformer are provided in table E.3.1.3.

### E.2.5 Shunt capacitor modelling

Shunt capacitors are modelled as Fixed Loads, where the number and phasing of fixed loads for each capacitor are given in table E.2.5.1, and:

- $F_{fc}$  Magnitude of Fixed Load for capacitor C [kVA]
- $F_{PF_{fc} = 0 \text{ lead}}$  Power factor of Fixed Load for capacitor C [ratio]
- $F_{ELV_{fc} = CLV}$  Energy voltage dependency of Fixed Load for capacitor C [ratio]
- $F_{DLV_{fc} = CLV}$  Demand voltage dependency of Fixed Load for capacitor C [ratio]
- $FLT_{fc} = 0$  Tariff rate of Fixed Load for capacitor C in all years [Rand/kWh]

$$F_{fc} = \frac{RC_c}{KC_c} \quad \text{E.2.5.1}$$

- $RC_c$  Rated reactive power of capacitor C [kVA<sub>r</sub>] (for all phases)
- $KC_c$  Number of phases of capacitor C. See table E.2.5.1.

Node technology	Capacitor Node Phasing	Number and phasing of capacitor Fixed Loads	$KC_c$
3PNStar	ABC	AN, BN and CN	3
1PN	AN	AN	1
	BN	BN	
	CN	CN	
3PDelta	ABC	AB, BC and CA	3
2PDelta	AB	AB	1
	BC	BC	
	CA	CA	
1PE (SWER)	AN (AE)	AN (AE)	1
	BN (BE)	BN (BE)	
	CN (CE)	CN (CE)	
2PN (bi-phase)	AB	AN and BN	2
	BC	BN and CN	
	CA	CN and AN	

Table E.2.5.1: Shunt capacitor Fixed Load modelling.

### E.3 LOAD LOSS ENERGY CALCULATION AND COSTING

The calculations are performed separately for each phase/neutral conductor in each branch. The notation Bp refers to branch B and phase/neutral p.

#### E.3.1 Year 1 time-of-use load loss energy

The load loss energy per ohm of resistance [kWh/Ω] of a phase or neutral conductor p in branch B in time interval t, day type d, and season s in year 1 is given by:

$$\text{Energy } L_{Bp t, d, s} = 1000 \cdot \frac{(E[E[\mu^2]]_{Bp t, d, s} + E[E[\sigma^2]]_{Bp t, d, s})}{V_B^2} \cdot i \quad \text{E.3.1.1}$$

Energy $L_{Bp t, d, s}$	Load loss energy per ohm of resistance of phase/neutral p in branch B in time interval t, day type d, and season s in year 1 [kWh/Ω]
$E[E[\mu^2]]_{Bp t, d, s}$	Expected value of the square of the load mean of phase/neutral p in branch B in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]
$E[E[\sigma^2]]_{Bp t, d, s}$	Expected value of the variance of the load of phase/neutral p in branch B in time interval t, day type d, and season s in year 1 [kVA <sup>2</sup> ]
$V_B$	Nominal phase to neutral voltage of branch B [V]

The above equation also applies to reactive power losses [kVAh/Ω] where the phase/neutral conductor reactance is used.

Cluster all variable loads supplied by branch B phase/neutral p into Load Bins where all the loads in a Load Bin have the same characteristic for the phase/neutral conductor under study:

- Same Load Group.
- Same technology scaling factor and current angle.
- Same transformation ratio.

Fixed loads are not clustered into bins.

$E[E[\mu^2]]_{Bp t, d, s}$  and  $E[E[\sigma^2]]_{Bp t, d, s}$  are given by:

$$E[E[\mu^2]]_{Bp t, d, s} = \left[ \sum_{L=1}^{LG_{Bp}} \sum_{l=1}^{LB_{BpL}} \left( SF_{BpLl} \cdot N_{BpLl} \cdot \overline{E[\mu_{L t, d, s}]} \cdot \text{Angle}(A_{BpLl} + \text{ARCCOS}(PF_{Ll, d, s})) \right) + \sum_{f=1}^{NF_{Bp}} FS_{BpAf} \cdot \overline{F}_f \cdot \text{Angle}(A_{Bpf} + \text{ARCCOS}(FPF_f)) \right]^2 \quad \text{E.3.1.2}$$

$$E[E[\sigma^2]]_{Bp t, d, s} = \sum_{L=1}^{LG_{Bp}} \left[ \sum_{l=1}^{LB_{BpL}} \left( (V[\mu_{L t, d, s}] + E[\sigma_{L t, d, s}^2]) \cdot N_{BpLl} \cdot SF_{BpLl}^2 + E[\rho_{L t, d, s}] \cdot E[\sigma_{L t, d, s}]^2 \cdot N_{BpLl} \cdot (N_{BpLl} - 1) \cdot SF_{BpLl}^2 \right) + \sum_{j=1}^{LB_{BpL}} \sum_{k=1, k \neq j}^{LB_{BpL}} SF_{BpLj} \cdot SF_{BpLk} \cdot \cos(A_{BpLj} - A_{BpLk}) \cdot N_{BpLj} \cdot N_{BpLk} \right] \quad \text{E.3.1.3}$$

- $LG_{Bp}$  Number of Load Groups supplied by branch B phase/neutral p in year 1
- $LB_{BpL}$  Number of Load Group L Load Bins supplied by branch B phase/neutral p in year 1
- $SF_{BpLl}, SF_{BpLj}, SF_{BpLk}$  Scaling factors of Load Group L Load Bins l, j and k respectively including the transformation effect in year 1 [per-unit]

$$SF_{BpLl} = \frac{K_{BpLl} \cdot SF_L}{TR_{BpLl}} \quad SF_{BpLj} = \frac{K_{BpLj} \cdot SF_L}{TR_{BpLj}} \quad SF_{BpLk} = \frac{K_{BpLk} \cdot SF_L}{TR_{BpLk}} \quad \text{E.3.1.4}$$

- $K_{BpLl}, K_{BpLj}, K_{BpLk}$  Technology scaling factors for Load Group L Load Bins l, j and k respectively (values are provided in table E.3.1.1) [per-unit]
- $TR_{BpLl}, TR_{BpLj}, TR_{BpLk}$  Transformation ratios of Load Group L Load Bins l, j and k respectively [per-unit]
- $N_{BpLl}, N_{BpLj}, N_{BpLk}$  Number of consumers in Load Group L Load Bins l, j and k respectively
- $A_{BpLl}, A_{BpLj}, A_{BpLk}$  Angles of Load Group L Load Bins l, j and k respectively [degrees]
- $NF_{Bp}$  Number of Fixed Loads
- $FS_{BpAf}$  Scaling factor at angle  $A_f$  of Fixed Load f including the transformation effect [per-unit]

$$FS_{BpAf} = \frac{K_{BpAf} \cdot FS_f}{TR_{BpAf}} \quad \text{E.3.1.5}$$

$K_{Bp f}$	Technology scaling factor of Fixed Load $f$ at angle $A_f$ (values are provided in table E.3.1.1) [per-unit]
$TR_{Bp f}$	Transformation ratio of Fixed Load $f$ [per-unit]
$A_{Bp f}$	Angle of Fixed Load $f$ [degrees]

Load power factors are assumed to be lagging. Fixed Loads used to model shunt capacitors have 0 leading power.

The scaling factor of each Load Group Load Bin and Fixed Load varies in each conductor/neutral depending on the transformation ratio between the conductor/neutral under consideration and the connection of the load, and the scaling to account for the phase to phase or phase to neutral connection of the load (all branches are modelled with phase to neutral nominal voltages).

The transformation ratio refers to the total per-unit turns ratio between the phase/neutral conductor (being studied) and the load. The total per-unit turns ratio is obtained by multiplying the per-unit turns ratios of all transformers and regulators between the phase/neutral conductor (being studied) and the load. The transformation ratio of transformer  $T$  (and voltage regulators) is given by:

$$TR_T = \frac{PV_T \cdot NSV_T \cdot TAP_T}{SV_T \cdot NPV_T} \quad E.3.1.6$$

$PV_T$	Rated primary phase to neutral voltage of transformer $T$ [V]
$SV_T$	Rated secondary phase to neutral voltage of transformer $T$ [V]
$NPV_T$	Nominal (system) primary phase to neutral voltage of transformer $T$ [V]
$NSV_T$	Nominal (system) secondary phase to neutral voltage of transformer $T$ [V]
$TAP_T$	Tap ratio (<1 boosting, 1 nominal, >1 bucking) of transformer $T$ [ratio]

A per-unit transformation ratio value of less than 1 implies boosting of the nominal secondary voltage.

The phasing connection of each load ( $LD_{Bp f}$ ,  $LD_{Bp Li}$ ,  $LD_{Bp Lj}$ ,  $LD_{Bp Lk}$ ) is determined by the transformation of the phasing of the load (at the point of connection to the network) to the branch/phase being studied. The supported technology transformations are summarised in table E.3.1.2, and the technology phasing transformations are detailed in table E.3.1.3.

Technology of Bp	Phase p	$LD_{Bp f_i}$ , $LD_{Bp L_i}$ , $LD_{Bp L_j}$ , $LD_{Bp L_k}$	$A_{Bp f_i}$ , $A_{Bp L_i}$ , $A_{Bp L_j}$ , $A_{Bp L_k}$	$K_{Bp f_i}$ , $K_{Bp L_i}$ , $K_{Bp L_j}$ , $K_{Bp L_k}$
Single Phase	P (A)	AN	0°	1
	N (A)	AN	0°	1
	P (B)	BN	0°	1
	N (B)	BN	0°	1
	P (C)	CN	0°	1
	N (C)	CN	0°	1
SWER	P (A)	AE	0°	1
	E (A)	AE	0°	1
	P (B)	BE	0°	1
	E (B)	BE	0°	1
	P (C)	CE	0°	1
	E (C)	CE	0°	1
Dual/Bi-phase	P (A) AB	AN	0°	1
	P (B) AB	BN	180°	1
	N AB	AN	0°	1
	N AB	BN	180°	1
	P (B) BC	BN	0°	1
	P (C) BC	CN	180°	1
	N BC	BN	0°	1
	N BC	CN	180°	1
	P (C) CA	CN	0°	1
	P (A) CA	AN	180°	1
	N CA	CN	0°	1
	N CA	AN	180°	1
Three Phase Star	P (A)	AN	0°	1
	P (A)	AB	-30° [2]	1/√3
	P (A)	CA	30° [2]	1/√3
	P (B)	BN	120°	1
	P (B)	AB	150° [2]	1/√3
	P (B)	BC	90° [2]	1/√3
	P (C)	CN	-120°	1
	P (C)	BC	-90° [2]	1/√3
	P (C)	CA	-150° [2]	1/√3
	N	AN	0°	1
	N	BN	120°	1
	N	CN	-120°	1
Three Phase Delta and Phase-to-phase Delta	P (A)	AE	0° [3]	1
	P (A)	AB	-30°	1/√3
	P (A)	CA	30°	1/√3
	P (B)	BE	120° [3]	1
	P (B)	AB	150°	1/√3
	P (B)	BC	90°	1/√3
	P (C)	CE	-120° [3]	1
	P (C)	BC	-90°	1/√3
	P (C)	CA	-150°	1/√3
	E	AE	0° [3]	1
	E	BE	120° [3]	1
	E	CE	-120° [3]	1

Table E.3.1.1: Technology current angles and scaling factors for load phasing connection.

[1] Phase-to-phase connected load in bi-phase network, [2] Phase-to-phase connected load in star network, [3] Phase to Earth connected load in delta network.

Transformer Primary	Transformer Secondary					
	3PNStar	1PN	3PDelta	2PDelta	1PE (SWER)	2PN (bi-phase)
3PNStar	Y		Y			
1PN		Y			Y	Y
3PDelta	Y		Y			
2PDelta		Y		Y	Y	Y
1PE (SWER)		Y			Y	Y
2PN (bi-phase)						Y

Table E.3.1.2: Supported technology transformations

Transformer technology	Secondary load phasing (LD <sub>s</sub> )	Transformer primary phasing	Primary load phasing (LD <sub>p</sub> )	Phasing of no-load Fixed Loads	KPP <sub>T</sub>	KPS <sub>T</sub>
3PNStar / 3PNStar	AN	ABC	AN	AN, BN and CN	3	3
	BN		BN			
	CN		CN			
3PNStar / 3PDelta YNd1	AB	ABC	BN	AN, BN and CN	3	3
	BC		CN			
	CA		AN			
3PNStar / 3PDelta YNd11	AB	ABC	AN	AN, BN and CN	3	3
	BC		BN			
	CA		CN			
1PN / 1PN	AN	AN	AN	AN	1	1
	BN	BN	BN	BN		
	CN	CN	CN	CN		
1PN / 1PE (SWER)	AN (AE)	AN	AN	AN	1	1
	BN (BE)	BN	BN	BN		
	CN (CE)	CN	CN	CN		
1PN / 2PN (bi-phase)	AN	AN	AN	AN	1	2
	BN	AN	AN	AN		
	BN	BN	BN	BN		
	CN	BN	BN	BN		
	CN	CN	CN	CN		
	AN	CN	CN	CN		
3PDelta / 3PNStar Dyn11	AN	ABC	CA	AB, BC and CA	3	3
	BN		AB			
	CN		BC			
3PDelta / 3PNStar Dyn1	AN	ABC	AB	AB, BC and CA	3	3
	BN		BC			
	CN		CA			
3PDelta / 3PDelta	AB	ABC	AB	AB, BC and CA	3	3
	BC		BC			
	CA		CA			
2PDelta / 1PN	AN	AB	AB	AB	1	1
	BN	BC	BC	BC		
	CN	CA	CA	CA		
2PDelta / 2PDelta	AB	AB	AB	AB	1	1
	BC	BC	BC	BC		
	CA	CA	CA	CA		

Table E.3.1.3a: Transformer secondary to primary load phasing transformation

Transformer technology	Secondary load phasing (LD <sub>s</sub> )	Transformer primary phasing	Primary load phasing (LD <sub>p</sub> )	Phasing of no-load Fixed Loads	KPP <sub>T</sub>	KPS <sub>T</sub>
2PDelta / 1PE (SWER)	AN (AE)	AB	AB	AB	1	1
	BN (BE)	BC	BC	BC		
	CN (CE)	CA	CA	CA		
2PDelta / 2PN (bi-phase)	AN	AB	AB	AB	1	2
	BN	AB	AB	AB		
	BN	BC	BC	BC		
	CN	BC	BC	BC		
	CN	CA	CA	CA		
1PE (SWER) / 1PN	AN	AN (AE)	AN (AE)	AN (AE)	1	1
	BN	BN (BE)	BN (BE)	BN (BE)		
	CN	CN (CE)	CN (CE)	CN (CE)		
1PE (SWER) / 1PE (SWER)	AN (AE)	AN (AE)	AN (AE)	AN (AE)	1	1
	BN (BE)	BN (BE)	BN (BE)	BN (BE)		
	CN (CE)	CN (CE)	CN (CE)	CN (CE)		
1PE (SWER) / 2PN (bi-phase)	AN	AN (AE)	AN (AE)	AN (AE)	1	2
	BN	AN (AE)	AN (AE)	AN (AE)		
	BN	BN (BE)	BN (BE)	BN (BE)		
	CN	BN (BE)	BN (BE)	BN (BE)		
	CN	CN (CE)	CN (CE)	CN (CE)		
2PN (bi-phase) / 2PN (bi-phase)	AN	AB	AN	AN and BN	2	2
	BN	AB	BN	AN and BN		
	BN	BC	BN	BN and CN		
	CN	BC	CN	BN and CN		
	CN	CA	CN	CN and AN		
	AN	CA	AN	CN and AN		

Table E.3.1.3b: Transformer secondary to primary load phasing transformation

### E.3.2 Year 1 load apportionment per season

The sum of the apparent energy consumption [kVAh] of Load Group L in season s in year 1 is given by:

$$\overline{LG AE}_{BpLs} = i \cdot \sum_{d=1}^{DT} D_{dm} \cdot \sum_{t=i}^{24/i} \sum_{l=1}^{LB_{BpL}} \left( SF_{BpLl} \cdot N_{BpLl} \cdot \overline{E[\mu_{L,t,d,s}]_{Angle(A_{BpLl} + ARCCOS(PF_{L,t,d,s}))}} \right. \\ \left. + SF_{BpLl} \cdot N_{BpLl} \cdot \overline{E[\mu_{L,t,d,s}]_{Angle(0)}} \cdot \bar{e}_{Angle(0)} \right) \quad E.3.2.1$$

$\overline{LG AE}_{BpLs}$  Sum of the apparent energy consumption of Load Group L in season s in year 1 [kVAh]

e  $10^{-6}$

A multiple of e is introduced into the above equation to prevent divide by zero errors and ensure correct load apportionment (in subsequent calculations) where branch loads are perfectly balanced.

The sum of the apparent energy consumption [kVAh] of all of the Fixed Loads in season s in year 1 is given by:

$$\overline{FL AE}_{Bp s} = \sum_{d=1}^{DT} \left( D_{dm} \cdot 24 \cdot \sum_{f=1}^{NF_{Bp}} \left( FS_{Bp Af} \cdot \overline{F}_f \cdot \text{Angle}(A_{Bp f} + \text{ARCCOS}(FPF_f)) + FS_{Bp Af} \cdot F_f \cdot \bar{e}_{\text{Angle}(0)} \right) \right) \quad \text{E.3.2.2}$$

**FL AE<sub>Bp s</sub>** Sum of the apparent energy consumption of the Fixed Loads in season s in year 1 [kVAh]

The sum of the apparent energy consumption [kVAh] of all loads in season s in year 1 is given by:

$$\overline{SUM AE}_{Bp s} = \left( \sum_{L=1}^{LG_{Bp}} \overline{LG AE}_{Bp L s} \right) + \overline{FL AE}_{Bp s} \quad \text{E.3.2.3}$$

**SUM AE<sub>Bp s</sub>** Sum of the apparent energy consumption of all loads in season s in year 1 [kVAh]

The per-unit apparent energy contribution of Load Group L in season s in year 1 is given by:

$$PU LG AE_{Bp L s} = \text{Re} \left( \frac{\overline{LG AE}_{Bp L s}}{\overline{SUM AE}_{Bp s}} \right) \quad \text{E.3.2.4}$$

**PU LG AE<sub>Bp L s</sub>** Per-unit contribution of Load Group L to the total apparent energy in season s in year 1 [per-unit]

If the total load supplied by all loads is zero then the above equation will result in a divide by zero error. This error is prevented as follows:

If magnitude(SUM AE<sub>Bp s</sub>) is zero then PU LG AE<sub>Bp L s</sub> = 0 and subsequently AE Forecast<sub>Bp s y</sub> = 0.

The per-unit apparent energy contribution of the Fixed Loads in season s in year 1 is given by:

$$PU FL AE_{Bp s} = \text{Re} \left( \frac{\overline{FL AE_{Bp s}}}{\overline{SUM AE_{Bp s}}} \right) \quad \text{E.3.2.5}$$

$PU FL AE_{Bp s}$  Per-unit contribution of the Fixed Loads to the total apparent energy in season s in year 1 [per-unit]

If magnitude( $\overline{SUM AE_{Bp s}}$ ) is zero then  $PU FL AE_{Bp s}=0$  and subsequently  $AE Forecast_{Bp s y}=0$ .

### E.3.3 Seasonal energy forecast

The per-unit increase in apparent energy in season s in year y (relative to year 1) is given by:

$$AE Forecast_{Bp s y} = \left| \sum_{L=1}^{LG_{Bp}} PU LG AE_{Bp L s} \cdot F_{L y} + PU FL AE_{Bp s} \right| \quad \text{E.3.3.1}$$

$AE Forecast_{Bp s y}$  Per-unit increase in apparent energy in season s in year y (relative to year 1) [per-unit]

$$\text{If } y > U \text{ then } F_{L y} = F_{L U} \quad \text{E.3.3.2}$$

$F_{L U}$  Per-unit increase in apparent energy consumption of Load Group L in the forecast limit year U (relative to year 1) [per-unit]

### E.3.4 Year 1 load apportionment per time interval

The apparent power [kVA] of Load Group L in time interval t, day type d, and season s in year 1 is given by:

$$\overline{LG AP_{Bp L t, d, s}} = \sum_{i=1}^{LB_{Bp L}} \left( SF_{Bp L i} \cdot N_{Bp L i} \cdot \overline{E[\mu_{L t, d, s}]_{\text{Angle}(A_{Bp L i} + \text{ARCCOS}(PF_{L t, d, s}))}} \right. \\ \left. + SF_{Bp L i} \cdot N_{Bp L i} \cdot \overline{E[\mu_{L t, d, s}]_{\text{Angle}(0)}} \right) \quad \text{E.3.4.1}$$

$LG AP_{BpL t,d,s}$  Apparent power of Load Group L in time interval t, day type d, and season s in year 1 [kVA]

The apparent power [kVA] of Fixed Load f in time interval t, day type d, and season s in year 1 is given by:

$$\overline{FL AP_{Bp f t,d,s}} = FS_{Bp A f} \cdot \overline{F_f} \cdot e^{j \text{Angle}(A_{Bp f} + \text{ARCCOS}(FPF_f))} + FS_{Bp A f} \cdot F_f \cdot \overline{e^{\text{Angle}(0)}} \quad \text{E.3.4.2}$$

$FL AP_{Bp f t,d,s}$  Apparent power of Fixed Load f in time interval t, day type d, and season s in year 1 [kVA]

The sum of the apparent power [kVA] of all loads in time interval t, day type d, and season s in year 1 is given by:

$$\overline{SUM AP_{Bp t,d,s}} = \left( \sum_{L=1}^{LG_{Bp}} \overline{LG AP_{Bp L t,d,s}} \right) + \left( \sum_{f=1}^{NF_{Bp}} \overline{FL AP_{Bp f t,d,s}} \right) \quad \text{E.3.4.3}$$

$SUM AP_{Bp t,d,s}$  Sum of the apparent power of all loads in time interval t, day type d, and season s in year 1 [kVA]

The per-unit apparent power contribution of Load Group L in time interval t, day type d, and season s in year 1 is given by:

$$PU LG AP_{Bp L t,d,s} = \text{Re} \left( \frac{\overline{LG AP_{Bp L t,d,s}}}{\overline{SUM AP_{Bp t,d,s}}} \right) \quad \text{E.3.4.4}$$

$PU LG AP_{Bp L t,d,s}$  Per-unit contribution of Load Group L to the total apparent power in time interval t, day type d, and season s in year 1 [per-unit]

The per-unit apparent power contribution of Fixed Load f in time interval t, day type d, and season s in year 1 is given by:

$$PU FL AP_{Bp f t,d,s} = \text{Re} \left( \frac{\overline{FL AP_{Bp f t,d,s}}}{\overline{SUM AP_{Bp t,d,s}}} \right) \quad \text{E.3.4.5}$$

**PU FL AP<sub>Bp f t,d,s</sub>** Per-unit contribution of Fixed Load f to the total apparent power in time interval t, day type d, and season s in year 1 [per-unit]

If the total load supplied by all loads is zero then the above two equations will result in divide by zero errors. These errors are prevented as follows:

If magnitude(SUM AP<sub>Bp t,d,s</sub>) is zero then PU LG AP<sub>Bp Lt,d,s</sub>=0, PU FL AP<sub>Bp f t,d,s</sub>=0 and ECV<sub>Bp t,d,s</sub>=0 (ECV<sub>Bp t,d,s</sub> is then not calculated as per equation E.3.5.1).

### E.3.5 Year y effective time-of-use cost of load loss energy

The effective cost of load loss active energy [Rand/kWh] in time interval t, day type d, and season s in year y incorporating the effect of load energy voltage dependency and revenue recovery is given by:

$$ECV_{Bp t,d,s,y} = \frac{\sum_{L=1}^{LG_{Bp}} |PU LG AP_{Bp Lt,d,s}| \cdot F_{Ly} \cdot \left( EC_{t,d,s} \cdot PU EC_y \cdot (1 - ELV_{BpL}) + ELV_{BpL} \cdot LT_L \cdot PU LT_y \cdot LR_L \right) + \sum_{f=1}^{NF_{Bp}} |PU FL AP_{Bp f t,d,s}| \cdot \left( EC_{t,d,s} \cdot PU EC_y \cdot (1 - FELV_{Bp f}) + FELV_{Bp f} \cdot FLT_f \cdot PU LT_y \cdot FLR_f \right)}{\sum_{L=1}^{LG_{Bp}} |PU LG AP_{Bp Lt,d,s}| \cdot F_{Ly} + \sum_{f=1}^{NF_{Bp}} |PU FL AP_{Bp f t,d,s}|} \quad E.3.5.1$$

**ECV<sub>Bp t,d,s,y</sub>** Effective cost of load loss active energy in time interval t, day type d and season s in year y incorporating load energy voltage dependency [Rand/kWh]

**ELV<sub>BpL</sub>** Energy voltage dependency of Load Group L for branch Bp [ratio]

**FELV<sub>Bp f</sub>** Energy voltage dependency of Fixed Load f for branch Bp [ratio]

$$ELV_{BpL} = \frac{(N_{BpL} - N_{BpL tap}) \cdot ELV_L}{N_{BpL}}$$

*If there is an auto-tap transformer between branch Bp and load f then* E.3.5.2

$$FELV_{Bp f} = 0, \text{ else } FELV_{Bp f} = FELV_f$$

**N<sub>BpL</sub>** Number of consumers in Load Group L supplied by branch Bp

**N<sub>BpL tap</sub>** Number of consumers in Load Group L that have an auto-tap transformer between them and branch Bp

Note: Time-of-use Customer Tariffs could be included whereby  $LT_L$  becomes time-of-use i.e  $LT_{L,t,d,s}$ .

### E.3.6 Lifetime load loss energy and cost (extrapolation of year 1 results)

The lifetime apparent energy [kVAh] supplied over the evaluation period E years is given by:

$$Lifetime AE_{Bp} = \sum_{s=1}^S \left( \left( \sum_{y=1}^E AE Forecast_{Bps y} \right) \cdot \overline{SUM AE_{Bps}} \right) \quad E.3.6.1$$

Lifetime  $AE_{Bp}$  Apparent energy supplied by phase/neutral p in branch B [kVAh]

The lifetime active energy Loss per ohm of resistance [kWh/ $\Omega$ ] over the evaluation period is given by:

$$Lifetime AEL_{Bp} = \sum_{s=1}^S \left( \left( \sum_{y=1}^E AE Forecast_{Bps y} \right)^2 \cdot \left( \sum_{d=1}^{DT} D_{ds} \cdot \sum_{t=i}^{24/i} Energy L_{Bpt,d,s} \right) \right) \quad E.3.6.2$$

Lifetime  $AEL_{Bp}$  Lifetime active load loss energy of phase/neutral p in branch B per ohm of resistance [kWh/ $\Omega$ ]

The lifetime reactive energy loss per ohm of reactance [kVArh/ $\Omega$ ] over the evaluation period is also given by equation E.3.6.2, but reactance is used instead of resistance.

Lifetime  $REL_{Bp}$  Lifetime reactive load loss energy of phase/neutral p in branch B per ohm of reactance [kVArh/ $\Omega$ ]

The lifetime active load loss energy and voltage drop cost per ohm of resistance [Rand/ $\Omega$ ] over the evaluation period is given by:

$$Lifetime AELC_{Bp} = \sum_{s=1}^S \left( \sum_{y=1}^E \left( \frac{AE Forecast_{Bps y}^2}{PU NDR_y} \cdot \sum_{d=1}^{DT} \left( D_{ds} \cdot \sum_{t=i}^{24/i} (Energy L_{Bpt,d,s} \cdot ECV_{Bpt,d,s,y}) \right) \right) \right) \quad E.3.6.3$$

Lifetime  $AELC_{Bp}$  Lifetime active load loss energy and voltage drop cost of phase/neutral p in branch B per ohm of resistance [Rand/ $\Omega$ ]

PU  $NDR_y$  Per-unit Net Discount Rate in year y (relative to year 1) [per-unit]

$$PU\ NDR_y = PU\ NDR_{y-1} \cdot (1 + NDR_y) \quad E.3.6.4$$

For year  $y=1$ ,  $PU\ NDR_{y-1}$  (i.e.  $PU\ NDR_0$ ) is unity.

The lifetime reactive load loss energy cost per ohm of reactance [Rand/ $\Omega$ ] over the evaluation period is given by:

$$Lifetime\ RELC_{Bp} = REC_{load} \cdot \sum_{s=1}^S \left( \left( \sum_{y=1}^E \frac{AE\ Forecast_{Bps\ y}^2}{PU\ NDR_y} \right) \cdot \left( \sum_{d=1}^{DT} D_{ds} \cdot \sum_{t=i}^{24/i} Energy\ L_{Bpt,d,s} \right) \right) \quad E.3.6.5$$

Lifetime  $RELC_{Bp}$  Lifetime reactive load loss energy cost of phase/neutral p in branch B per ohm of reactance [Rand/ $\Omega$ ]

## E.4 LOAD LOSS DEMAND CALCULATION AND COSTING

The load loss demand calculations are performed separately for each phase/neutral conductor. The notation Bp refers to branch B and phase/neutral p.

### E.4.1 Seasonal apparent demand forecast

The per-unit increase in apparent demand at the system peak (t=PDT and d=PDD) in season s in year y (relative to year 1) is given by:

$$AD\ Forecast_{Bp\ s\ y} = \left| \begin{array}{l} \sum_{L=1}^{LG_{Bp}} PU\ LG\ AP_{BpL\ t=PDT, d=PDD, s} \cdot FD_{L\ y} \\ + \sum_{f=1}^{NF_{Bp}} PU\ FL\ AP_{Bpf\ t=PDT, d=PDD, s} \end{array} \right| \quad E.4.1.1$$

AD Forecast<sub>Bp s y</sub> Per-unit increase in apparent demand at the system peak in season s in year y (relative to year 1) [per-unit]

$$\text{If } y > U \text{ then } FD_{L\ y} = FD_{L\ U} \quad E.4.1.2$$

FD<sub>L U</sub> Per-unit increase in apparent demand of Load Group L in the forecast limit year U (relative to year 1) [per-unit]

### E.4.2 Year y effective cost of load loss demand

The effective cost of active load loss demand [Rand/kW] at the system peak in season s in year y incorporating the effect of load demand voltage dependency is given by:

$$DCV_{Bp\ s\ y} = \frac{\sum_{L=1}^{LG_{Bp}} |PU\ LG\ AP_{BpL\ t=PDT, d=PDD, s}| \cdot FD_{L\ y} \cdot (DC_s \cdot PU\ DC_y \cdot (1 - DLV_{BpL})) + \sum_{f=1}^{NF_{Bp}} |PU\ FL\ AP_{Bpf\ t=PDT, d=PDD, s}| \cdot (DC_s \cdot PU\ DC_y \cdot (1 - FDLV_{Bpf}))}{\sum_{L=1}^{LG_{Bp}} |PU\ LG\ AP_{BpL\ t=PDT, d=PDD, s}| \cdot FD_{L\ y} + \sum_{f=1}^{NF_{Bp}} |PU\ FL\ AP_{Bpf\ t=PDT, d=PDD, s}|} \quad E.4.2.1$$

$DCV_{Bp s y}$	Effective cost of active load loss demand at the system peak in season $s$ in year $y$ incorporating the effect of load demand voltage dependency [Rand/kW]
$DLV_{Bp L}$	Demand voltage dependency of Load Group $L$ for branch $Bp$ [ratio]
$FDLV_{Bp f}$	Demand voltage dependency of Fixed Load $f$ for branch $Bp$ [ratio]

$$DLV_{Bp L} = \frac{(N_{Bp L} - N_{Bp L tap}) \cdot DLV_L}{N_{Bp L}}$$

If there is an auto – tap transformer between branch  $Bp$  and load  $f$  then E.4.2.2

$$FDLV_{Bp f} = 0, \text{ else } FDLV_{Bp f} = FDLV_f$$

Note: Customer Tariff demand charges could be included as per equation 10.3.2, where the Customer Tariff demand charge could be specified for each season of the year. The demand cost calculations would need to be performed for each time interval. In each time interval the ULT and CT demand charges would need to be adjusted (set to zero or left unchanged) to account for whether the time interval coincides with the system or Load Group maximum demand time intervals respectively. The number of calculations for demand loss costing would increase significantly as demand losses would need to be evaluated in each time interval and not just PDT/PDD.

#### E.4.3 Lifetime load loss demand cost (extrapolation of year 1 results)

The lifetime active load loss demand cost per ohm of resistance [Rand/ $\Omega$ ] over the evaluation period is given by:

$$Lifetime\ DLC_{Bp} = \sum_{s=1}^S \left( \sum_{y=1}^E \left( \frac{AD\ Forecast_{Bp s y}^2 \cdot Energy\ L_{Bp t=PDT, d=PDD, s} \cdot DCV_{Bp s y}}{PU\ NDR_y \cdot i} \right) \right) \quad E.4.3.1$$

Lifetime  $DLC_{Bp}$  Lifetime active load loss demand cost of phase/neutral  $p$  in branch  $B$  per ohm of resistance [Rand/ $\Omega$ ]

## E.5 NO-LOAD LOSS ENERGY AND DEMAND CALCULATION AND COSTING

The lifetime cost of active no-load loss power (energy component) [Rand/kW] over the evaluation period is given by:

$$ANLELC = i \cdot \left( \sum_{y=1}^E \frac{PU EC_y}{PU NDR_y} \right) \cdot \sum_{s=1}^S \sum_{d=1}^{DT} D_{ds} \cdot \sum_{t=i}^{24/i} EC_{t,d,s} \quad E.5.1$$

**ANLELC** Lifetime cost of active no-load loss power (energy component) over the evaluation period [Rand/kW]

The lifetime cost of reactive no-load loss power [Rand/kVAr] over the evaluation period is given by:

$$RNLELC = \frac{REC_{no-load} \cdot Eh}{E} \cdot \left( \sum_{y=1}^E \frac{1}{PU NDR_y} \right) \quad E.5.2$$

**RNLELC** Lifetime cost of reactive no-load loss power over the evaluation period [Rand/kVAr]

$$Eh = E \cdot 24 \cdot \sum_{s=1}^S \sum_{d=1}^{DT} D_{ds} \quad E.5.3$$

**Eh** Number of hours in the evaluation period in year 1[h]

The lifetime cost of active no-load loss power (demand component) [Rand/kW] over the evaluation period is given by:

$$ANLDLC = \left( \sum_{y=1}^E \frac{PU DC_y}{PU NDR_y} \right) \cdot \sum_{s=1}^S DC_s \quad E.5.4$$

**ANLDLC** Lifetime cost of active no-load loss power (demand component) over the evaluation period [Rand/kW]

## E.6 CONDUCTOR SIZE OPTIMISATION

Lifetime load loss energy cost has been calculated for each phase/neutral conductor  $p$  in each branch  $B$ . In this step the conductor size in each branch is optimised to minimise the capital and lifetime load loss cost. The conductor size optimisation is not constrained by a maximum voltage drop limit, but does consider conductor thermal ratings.

### E.6.1 Peak load calculation

The mean loading in phase/neutral conductor  $p$  of branch  $B$  in time interval  $t$ , day type  $d$  and season  $s$  in year 1 is given by:

$$E[E[\mu]]_{Bp\ t,d,s} = \sqrt{E[E[\mu^2]]_{Bp\ t,d,s}} \quad \text{E.6.1.1}$$

$E[E[\mu]]_{Bp\ t,d,s}$  Expected value of the load mean of phase/neutral  $p$  in branch  $B$  in time interval  $t$ , day type  $d$ , and season  $s$  in year 1 [kVA]

The standard deviation of the loading in phase/neutral conductor  $p$  of branch  $B$  in time interval  $t$ , day type  $d$  and season  $s$  in year 1 is given by:

$$E[E[\sigma]]_{Bp\ t,d,s} = \sqrt{E[E[\sigma^2]]_{Bp\ t,d,s}} \quad \text{E.6.1.2}$$

$E[E[\sigma]]_{Bp\ t,d,s}$  Expected value of the standard deviation of the load of phase/neutral  $p$  in branch  $B$  in time interval  $t$ , day type  $d$ , and season  $s$  in year 1 [kVA]

Search  $E[E[\mu]]_{Bp\ t,d,s}$  for year 1 and find the interval of maximum mean loading:

$$E[E[\mu]]_{Bp\ t=t_{Bp\ Max}, d=d_{Bp\ Max}, s=s_{Bp\ Max}} = \max(E[E[\mu]]_{Bp\ t,d,s}) \quad \text{E.6.1.3}$$

$t_{Bp\ Max}$ ,  $d_{Bp\ Max}$  and  $s_{Bp\ Max}$  are the time interval, day type and season respectively of maximum mean loading of phase/neutral  $p$  in branch  $B$  in year 1.

The maximum peak loading of phase/neutral conductor p in branch B in year 1 is given by:

$$PL_{Bp1} = E[E[\mu]]_{Bp\ t=t_{Bp\ Max}, d=d_{Bp\ Max}, s=s_{Bp\ Max}} + PDS \cdot E[E[\sigma]]_{Bp\ t=t_{Bp\ Max}, d=d_{Bp\ Max}, s=s_{Bp\ Max}} \quad E.6.1.4$$

$PL_{Bp1}$  Maximum peak loading of phase/neutral p in branch B in year 1 [kVA]

The ratio of the year PDY load to year 1 load is given by:

$$LIR_{Bp\ PDY} = \left[ \begin{array}{l} \sum_{L=1}^{LG_{Bp}} PU\ LG\ AP_{Bp\ L\ t=t_{Bp\ Max}, d=d_{Bp\ Max}, s=s_{Bp\ Max}} \cdot FD_{L\ y=PDY} \\ + \sum_{f=1}^{NF_{Bp}} PU\ FL\ AP_{Bp\ f\ t=t_{Bp\ Max}, d=d_{Bp\ Max}, s=s_{Bp\ Max}} \end{array} \right] \quad E.6.1.5$$

$LIR_{Bp\ PDY}$  Ratio of the year PDY peak load to year 1 peak load [ratio]

The maximum peak load in phase/neutral conductor p in branch B in year PDY is given by:

$$PL_{Bp\ PDY} = PL_{Bp1} \cdot LIR_{Bp} \quad E.6.1.6$$

$PL_{Bp\ PDY}$  Maximum peak load in phase/neutral p in branch B in year PDY [kVA]

The lifetime cost per kW of load loss active power at peak loading in year PDY is given by:

$$PLALC_{Bp} = \frac{Lifetime\ AELC_{Bp} + Lifetime\ DLC_{Bp}}{1000 \cdot \left( \frac{PL_{Bp\ PDY}}{V_B} \right)^2} \quad E.6.1.7$$

$PLALC_{Bp}$  Lifetime cost of load loss active power during peak loading ( $PL_{Bp\ PDY}$ ) in phase/neutral p in branch B in year PDY [Rand/kW]

Note that  $PLALC_{Bp}$  incorporates voltage drop cost.

The lifetime cost of load loss reactive power at peak loading in year PDY is given by:

$$PLRLC_{Bp} = \frac{\text{Lifetime } RELC_{Bp}}{1000 \cdot \left( \frac{PL_{BpPDY}}{V_B} \right)^2} \quad \text{E.6.1.8}$$

$PLRLC_{Bp}$  Lifetime cost of load loss reactive power during peak loading ( $PL_{BpPDY}$ ) in phase/neutral p in branch B in year PDY [Rand/kVAr]

## E.6.2 Conductor size optimisation

The lifetime load loss (active and reactive, energy and demand) and voltage drop cost for a branch B with conductor C is given by:

$$\text{Lifetime } BELC_{BC} = \sum_{p=1}^{P_B} \left( \left( \text{Lifetime } AELC_{Bp} + \text{Lifetime } DLC_{Bp} \right) \cdot R_{BCp} + \text{Lifetime } RELC_{Bp} \cdot X_{BCp} \right) \quad \text{E.6.2.1}$$

$\text{Lifetime } BELC_{BC}$  Lifetime load loss and voltage drop cost of branch B using conductor C [Rand]

$R_{BCp}$  Resistance of phase/neutral p of conductor C in branch B [ $\Omega$ ]

$X_{BCp}$  Reactance of phase/neutral p of conductor C in branch B [ $\Omega$ ]

$P_B$  Number of phases and neutrals in branch B

$R_{BCp}$  and  $X_{BCp}$  are obtained by multiplying the branch B length [km] by the per-unit length resistance [ $\Omega/\text{km}$ ] and reactance [ $\Omega/\text{km}$ ] of conductor C.

Note that the per-unit length resistance and reactance may vary for phase and neutral conductors.

The optimal cable/line size  $C_{B\ opt}$  in branch B is the cable/line size that minimises the sum of the cable/line capital and lifetime load loss and voltage drop costs, and meets the thermal rating requirement:

$$C_{B\ opt} = C \text{ for } \min(\text{Lifetime } BELC_{BC} + CC_{BC}) \text{ where } \frac{\max(PL_{BP\ PDY}) \cdot 1000}{V_B} \leq AC_{BC} \quad \text{E.6.2.2}$$

$C_{B\ opt}$	Optimal cable/line size in branch B
$CC_{BC}$	Capital cost of cable/line size C in branch B [Rand]
$AC_{BC}$	Thermal rating of cable/line size C in branch B [amps]
$\text{Max}(PL_{BP\ PDY})$	Maximum peak load of all phases/neutral in branch B in year PDY [kVA]

$CC_{BC}$  is obtained by multiplying the branch B length [km] by the per-unit cost [Rand/km] of cable/line size C.

## E.7 CONDUCTOR LIFETIME COST RESULTS

Based on the user defined branch cable/line size or optimised branch cable/line size (where a list of cable/line sizes is provided for a branch), the following results are calculated for each branch:

$CC_{B\ Copt}$	Capital cost for branch B using cable/line size $C_{B\ opt}$ [Rand]
Lifetime $AEL_{B\ Copt}$	Lifetime active load loss energy for branch B using cable/line size $C_{B\ opt}$ [kWh]
Lifetime $AELC_{B\ Copt}$	Lifetime active load loss energy and voltage drop cost for branch B using cable/line size $C_{B\ opt}$ [Rand]
Lifetime $REL_{B\ Copt}$	Lifetime reactive load loss energy for branch B using cable/line size $C_{B\ opt}$ [kWh]
Lifetime $RELC_{B\ Copt}$	Lifetime reactive load loss energy cost for branch B using cable/line size $C_{B\ opt}$ [Rand]
Lifetime $DLC_{B\ Copt}$	Lifetime active load loss demand cost for branch B using cable/line size $C_{B\ opt}$ [Rand]
Lifetime $LC_{B\ Copt}$	Lifetime load loss (energy and demand, active and reactive) and voltage drop cost for branch B using cable/line size $C_{B\ opt}$ [Rand]
Lifetime $TC_{B\ Copt}$	Lifetime total cost (capital, load losses and voltage drop) for branch B using cable/line size $C_{B\ opt}$ [Rand]

<b>Max(PL<sub>B PDY</sub>) amps</b>	Maximum peak load of all phases/neutral in branch B in year PDY [amps]
<b>Max(PL<sub>B PDY</sub>)<sub>Copt</sub> PU</b>	Maximum peak load of all phases/neutral in branch B in year PDY as per-unit of the cable/line size C <sub>B opt</sub> rated current [per-unit]
<b>PLALC<sub>B</sub></b>	Lifetime active load loss power cost during peak loading in branch B in year PDY [Rand/kW]
<b>PLRLC<sub>B</sub></b>	Lifetime reactive load loss power cost during peak loading in branch B in year PDY [Rand/kVAr]

If a single cable/line size is specified for the branch then C<sub>B opt</sub> is the user defined cable/line size.

CC<sub>B Copt</sub> is obtained by multiplying the branch B length [km] by the per-unit cost [Rand/km] of cable/line size C<sub>B opt</sub>.

$$\text{Lifetime } AEL_{BCopt} = \sum_{p=1}^{P_B} \text{Lifetime } AEL_{B p} \cdot R_{BCopt p} \quad \text{E.7.1}$$

R<sub>BCopt p</sub> Resistance of phase/neutral p of cable/line size C<sub>B opt</sub> in branch B [Ω]

$$\text{Lifetime } AELC_{BCopt} = \sum_{p=1}^{P_B} \text{Lifetime } AELC_{B p} \cdot R_{BCopt p} \quad \text{E.7.2}$$

$$\text{Lifetime } REL_{BCopt} = \sum_{p=1}^{P_B} \text{Lifetime } REL_{B p} \cdot X_{BCopt p} \quad \text{E.7.3}$$

X<sub>BCopt p</sub> Reactance of phase/neutral p of cable/line size C<sub>B opt</sub> in branch B [Ω]

$$\text{Lifetime } RELC_{BCopt} = \sum_{p=1}^{P_B} \text{Lifetime } RELC_{B p} \cdot X_{BCopt p} \quad \text{E.7.4}$$

$$\text{Lifetime } DLC_{BCopt} = \sum_{p=1}^{P_B} \text{Lifetime } DLC_{B p} \cdot R_{BCopt p} \quad \text{E.7.5}$$

$$\text{Lifetime } LC_{BCopt} = \text{Lifetime } AELC_{BCopt} + \text{Lifetime } RELC_{BCopt} + \text{Lifetime } DLC_{BCopt} \quad \text{E.7.6}$$

$$\text{Lifetime } TC_{BCopt} = CC_{BCopt} + \text{Lifetime } LC_{BCopt} \quad \text{E.7.7}$$

$$\max(PL_{BPDY}) \text{ amps} = \frac{\max(PL_{BPDY}) \cdot 1000}{V_B} \quad \text{E.7.8}$$

$$\max(PL_{BPDY})_{Copt} \text{ PU} = \frac{\max(PL_{BPDY}) \text{ amps}}{AC_{BC}} \quad \text{E.7.9}$$

$$PLALC_B = \frac{\sum_{a=1}^p PLALC_{Bp=a}}{p} \quad \text{E.7.10}$$

$$PLRLC_B = \frac{\sum_{a=1}^p PLRLC_{Bp=a}}{p} \quad \text{E.7.11}$$

Note, these results are for the branch, and are not per phase.

# **F. APPENDIX F: SCOPE OF WORK FOR MONTE CARLO SIMULATION AND LOAD PARAMETER EXTRACTION**

The scope of work provided to Dr Heunis has been reformatted and condensed to conform to the terminology and formatting of this document. The enhancement of the existing software (as previously developed by Dr Heunis) was required to cater for time-of-use analysis and bi-phase and delta network technologies.

## **F.1 INPUT DATA FOR LOSS AND VOLTAGE CALCULATIONS**

All inputs and calculations are confined to analysis in a single year i.e. no future year loads and/or tariffs. Load changes to simulate future year step increases are modelled via adjustment of consumer Load Group scaling factors.

### **F.1.1 Energy tariff charge**

The load loss energy charge EC [Rand/kWh] in each 1 hour time interval, day type (weekday, Saturday and Sunday) and month is user defined in a tabular format.

### **F.1.2 Demand tariff charge**

The load loss demand charge DC [Rand/kVA] in each month is user defined in a tabular format.

The following inputs are used for the evaluation of load loss demand costs:

- PDD** Day type for load loss demand cost e.g. weekday
- PDT** Time interval for load loss demand cost e.g. 18
- PDP** Percentile value used in the extraction of the maximum load loss demand in each calculation iteration [per-unit]
- PDC** Percentile value used in the extraction of the maximum load loss demand from the results of all iterations [per unit] (this is the confidence level in the load loss demand calculation)

### F.1.3 Network data

The network is entered as per table F.1.3.1 for three phase star, table F.1.3.2 for bi-phase, and table F.1.3.3 for three phase delta. The networks are limited to a single radial network without explicit modelling of tee lines. A mixture of three customer Load Groups (LG1, LG2 and LG3) is catered for in a network study.

Node	mA			mB			mC			Rp (ohms)	Xp (ohms)	Rn (ohms)	Xn (ohms)
	LG1	LG2	LG3	LG1	LG2	LG3	LG1	LG2	LG3				
1													
2													
X													

Table F.1.3.1: Three phase star (loads connected phase to neutral)

Node	mA			mB			Rp (ohms)	Xp (ohms)	Rn (ohms)	Xn (ohms)
	LG1	LG2	LG3	LG1	LG2	LG3				
1										
2										
X										

Table F.1.3.2: Bi-phase (loads connected phase to neutral)

Node	mAB			mBC			mCA			Rp (ohms)	Xp (ohms)
	LG1	LG2	LG3	LG1	LG2	LG3	LG1	LG2	LG3		
1											
2											
X											

Table F.1.3.3: Three phase delta (no neutral conductor, loads connected phase to phase)

The network nominal voltage (VB) is specified (phase to neutral voltage for star and bi-phase, and phase to phase voltage for delta networks). Consumer currents in the load research data are recorded at nominal 230V. The consumer currents are scaled according to the network nominal voltage (scaling factor = 230/VB). The source voltage is 1 per-unit. All voltage results are reported in actual volts e.g. 206V. Networks can be saved for future re-use.

#### F.1.4 Voltage assessment parameters

Percentile voltage drop values are extracted from the simulated voltage drops, where:

- PVP** Percentile value used in the extraction of the minimum voltage in each calculation iteration [per-unit]
- PVC** Percentile value used in the extraction of the minimum voltage from the results of all iterations [per unit] (this is the confidence level in the voltage calculation)

#### F.1.5 Load data

- Start and stop dates (evaluation period) are specified by the user.
- Data marking is performed (poor data channels are identified and can be marked for exclusion).
- A summary (quantity of data not flagged as poor) of the available data (within the evaluation period) for each Load Group is provided.
- The load currents used in the simulation are scaled by user specified scaling factors SFLG1, SFLG2, SFLG3 for each Load Group. The scaling factors default to unity. Scaling factors are used to model step changes in future year loads.
- Each Load Group is assigned a power factor PFLG1, PFLG2, PFLG3. The default power factor is unity. The power factor is fixed for all time intervals.

## F.2 LOAD PARAMETER EXTRACTION

For a selected Load Group the following options for load parameter extraction are provided (the detailed load parameters in a "set" are described in appendix E.1.2):

- A set of parameters for each hour, day type and month.
- A set of parameters for each hour and day type (no differentiation between months).
- A set of parameters for each hour and month (no differentiation between day types).
- A set of parameters for each hour (no differentiation between day types or months).
- A set of parameters for each day type (no differentiation between hours or months).
- A set of parameters for each month (no differentiation between hours or day types).
- The date/time stamp, ADMD and standard deviation of the 5 maximum coincident 5 minute loadings in each month.

Include the number of consumers and 5-minute time intervals used in each parameter set calculation.

### **F.3 MONTE CARLO SIMULATION**

Loss calculations only consider active load loss demand and energy. Reactance is ignored for loss calculations and is only considered in voltage drop calculations.

**Step 1 (Customer assignment):** Randomly assign customers to the network with or without (user specified) replacement. Customer assignment is as per the Load Group specified in the network data.

**Step 2 (5 minute current and loss calculation):** For each 5 minute time interval in the evaluation period:

- Scale the current of each Load Group by the load scaling factor (SFLG1, SFLG2 and SFLG3) and voltage scaling factor ( $230/VB$ ).
- Calculate the current [amps] in each phase/neutral conductor of each branch (the effect of the load power factors must be included). Assume a constant current load model.
- Calculate the load loss power in each phase/neutral conductor of each branch and multiply by 1/12 to obtain the load loss energy [Wh].
- Sum the 5 minute load loss energy values in all branches/phases/neutrals to obtain the network load loss energy [Wh] in each 5 minute time interval.

**Step 3 (1 hour and monthly load loss energy values):** For each 1 hour time interval in the evaluation period:

- Sum the 5 minute network load loss energy values to obtain the network load loss energy in each 1 hour interval.
- Sum the network 1 hour load loss energy values for each day type in each month and divide by 1000 to obtain kWh, as per table F.3.1. Store these values as an output of this iteration.

Month X	Energy loss [kWh]			
	Time of day	Week	Sat	Sun
1				
2				
Etc.				
24				

Table F.3.1: Network load loss energy in each 1 hour time interval for each day type in each month (table is repeated for the number of months in the evaluation period)

Step 4 (Load loss demand percentile extraction): For the day type PDD and time interval PDT, for each month extract the PDP<sup>th</sup> percentile of the network 1 hour load loss demand. Store these values as an output of this iteration.

Step 5 (Voltage calculation): For the A phase of the last node (AB phases for delta network), calculate the voltage (phase to neutral in three phase star and bi-phase, and phase to phase for three phase delta) in all 5 minute time intervals. Extract and store the PVP<sup>th</sup> percentile voltage for each 1 hour interval for each day type in each month, as per table F.3.2. Note that the voltage calculation includes the effect of load power factor and network inductance. A constant current load model is used.

Month X	Phase AN (AB) PVP <sup>th</sup> percentile voltage			
	Time of day	Week	Sat	Sun
1				
2				
Etc.				
24				

Table F.3.2: Percentile voltage results for each 1 hour interval for each day type in each month (table is repeated for the number of months in the evaluation period)

Step 6: Return to Step 1, and repeat a user defined number of times (default 1000).

#### F.4 MONTE CARLO SIMULATION RESULT EXTRACTION

All results must be able to be exported to other applications such as MS Excel.

### F.4.1 Loss results

From the results of the typically 1000 iterations:

- Calculate the expected (average) network load loss energy [kWh] in each 1 hour time interval for each day type in each month.
- Calculate the expected network load loss energy cost [Rand] for each 1 hour interval for each day type in each month by multiplying the average load loss energy in each 1 hour interval with the corresponding hourly energy charge (EC).
- Present the results in tabular format as per table F.4.1.1.
- For the day type PDD and time interval PDT, for each month extract the PDC<sup>th</sup> percentile of the network load loss demand [kW].
- Multiply the PDC<sup>th</sup> percentile of the network load loss demand by the monthly demand charge (DC) to obtain the monthly load loss demand cost [Rands].
- Present the results in tabular format as per table F.4.1.2.

Month X	Energy loss [kWh]			Energy cost [Rands]			
	Time of day	Week	Sat	Sun	Week	Sat	Sun
1							
2							
Etc.							
24							

Table F.4.1.1: Expected network load loss energy and load loss energy costs in each 1 hour interval for each day type in each month (table is repeated for the number of months in the evaluation period)

Month	1	2	3	4	5	6	7	8	9	10	11	12
PDC <sup>th</sup> percentile load loss demand [kW]												
Load loss demand cost [Rands]												

Table F.4.1.2: Monthly load loss demand (PDC<sup>th</sup> percentile) and corresponding monthly load loss demand cost

## F.4.2 Voltage results

From the results of the typically 1000 iterations, for each 1 hour interval for each day type in each month calculate the PVC<sup>th</sup> percentile voltage of the PVP<sup>th</sup> percentile voltage. Present the results in tabular format as per table F.4.2.1.

Month X	Phase AN (AB) PVC <sup>th</sup> percentile of the PVP <sup>th</sup> percentile voltage		
	Week	Sat	Sun
1			
2			
Etc.			
24			

Table F.4.2.1: Minimum percentile voltage (last node on the network) for each 1 hour interval for each day type in each month (table is repeated for the number of months in the evaluation period)

# G. APPENDIX G: ENHANCED QOS LV VOLTAGE DROP CALCULATION AND TEST RESULTS

## G.1 ENHANCED QOS METHOD FOR 1 HOUR INTERVALS AND MIXED LOADS

### G.1.1 User settings

- p** Percentile voltage (the per-unit time that voltages will be above the calculated minimum voltage)
- cl** Per-unit confidence level

### G.1.2 Network topology

- $V_{LV}$**  Nominal phase to neutral LV supply voltage [V]
- $LG_f$**  Number of consumer Load Groups connected to LV feeder f
- $N_{L_f}$**  Number of consumers of Load Group L connected to LV feeder f
- $NF_f$**  Number of Fixed Loads connected to LV feeder f
- $R_{pc}$**  Phase conductor resistance between Load Group consumer c and the MV/LV transformer [ $\Omega$ ]
- $R_{nc}$**  Neutral conductor resistance between Load Group consumer c and the MV/LV transformer [ $\Omega$ ]
- $R_{pf}$**  Phase conductor resistance between Fixed Load f and the MV/LV transformer [ $\Omega$ ]
- $R_{nf}$**  Neutral conductor resistance between Fixed Load f and the MV/LV transformer [ $\Omega$ ]

### G.1.3 QOS voltage drop calculation

The voltage drop calculations are performed for each phase of each LV feeder for a user specified time interval t, day type d, season s and year y.

#### Step 1: Scale load parameters

The load parameters in appendix E.1.2 describing a Load Group have a kVA base. The load parameters are converted to a current base, and scaled according to the Load Group scaling factor and per-unit demand forecast.

$$E[\mu_{L t,d,s,y}]_{I SF} = E[\mu_{L t,d,s}] \cdot \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \quad G.1.3.1$$

$$V[\mu_{L t,d,s,y}]_{I SF} = V[\mu_{L t,d,s}] \cdot \left( \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \right)^2 \quad G.1.3.2$$

$$E[\sigma_{L t,d,s,y}]_{I SF} = E[\sigma_{L t,d,s}] \cdot \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \quad G.1.3.3$$

$$E[\sigma^2_{L t,d,s,y}]_{I SF} = E[\sigma^2_{L t,d,s}] \cdot \left( \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \right)^2 \quad G.1.3.4$$

$$E[\rho_{L t,d,s,y}]_{I SF} = E[\rho_{L t,d,m}] \quad G.1.3.5$$

$$G0_{L t,d,s,y I SF} = G0_{L t,d,m} \quad G.1.3.6$$

$$Ve0_{L t,d,s,y I SF} = Ve0_{L t,d,s} \cdot \left( \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \right)^2 \quad G.1.3.7$$

$$G1_{L t,d,s,y I SF} = G1_{L t,d,s} \cdot SF_L \cdot FD_{L y} \quad G.1.3.8$$

$$Ve1_{L t,d,s,y I SF} = Ve1_{L t,d,s} \cdot \left( \frac{1000 \cdot SF_L \cdot FD_{L y}}{V_{LV}} \right)^2 \quad G.1.3.9$$

$$FLI_f = F_f \cdot \frac{1000 \cdot FS_f}{V_{LV}} \quad G.1.3.10$$

$$V[\sigma_{L t,d,s,y}]_{I SF} = Ve0_{L t,d,s,y I SF} + G0_{L t,d,s,y I SF}^2 \cdot V[\mu_{L t,d,s,y}]_{I SF} \quad G.1.3.11$$

**Step 2: Minimum and maximum voltage limits for beta voltage distribution**

$$calc_{\min \max Lt,d,s,y} = \frac{C_L \cdot E[\mu_{Lt,d,s,y}]_{I SF} - E[\mu_{Lt,d,s,y}]_{I SF}^2 - E[\sigma_{Lt,d,s,y}]_{I SF}^2}{C_L \cdot E[\sigma_{Lt,d,s,y}]_{I SF}^2} \quad G.1.3.12$$

$$alpha_{\min \max Lt,d,s,y} = E[\mu_{Lt,d,s,y}]_{I SF} \cdot calc_{\min \max Lt,d,s,y} \quad G.1.3.13$$

$$beta_{\min \max Lt,d,s,y} = (C_L - E[\mu_{Lt,d,s,y}]_{I SF}) \cdot calc_{\min \max Lt,d,s,y} \quad G.1.3.14$$

$$Min_{\min \max Lt,d,s,y} = qbeta(0.001, alpha_{\min \max Lt,d,s,y}, beta_{\min \max Lt,d,s,y}) \cdot C_L \quad G.1.3.15$$

$$Max_{\min \max Lt,d,s,y} = qbeta(0.999, alpha_{\min \max Lt,d,s,y}, beta_{\min \max Lt,d,s,y}) \cdot C_L \quad G.1.3.16$$

$$Channel_{\max f t,d,s,y} = \sum_{L=1}^{LG_f} \sum_{j=1}^{N_{Lj}} \text{if}(a_{Lj} > 0, Max_{\min \max Lt,d,s,y}, Min_{\min \max Lt,d,s,y}) \cdot a_{Lj} \quad G.1.3.17$$

$$Channel_{\min f t,d,s,y} = \sum_{L=1}^{LG_f} \sum_{j=1}^{N_{Lj}} \text{if}(a_{Lj} < 0, Max_{\min \max Lt,d,s,y}, Min_{\min \max Lt,d,s,y}) \cdot a_{Lj} \quad G.1.3.18$$

$a_{Lc}$  =  $R_{nc} + R_{pc}$  if consumer c is connected to the phase for which the voltage is being calculated, else if consumer c is connected to another phase  $a_{Lc} = -0.5 \cdot R_{nc}$  for star technology and  $a_{Lc} = -R_{nc}$  for bi-phase technology [Q]

**Step 3: Expected value of voltage drop due to the mean current**

$$E_{vdmu f t,d,s,y} = \sum_{L=1}^{LG_f} \left[ E[\mu_{Lt,d,s,y}]_{I SF} \cdot \sum_{i=1}^{N_{Lj}} a_{Lj} \right] \quad G.1.3.19$$

**Step 4: Expected voltage drop standard deviation**

$$K_{1f t, d, s, y} = \sum_{L=1}^{LG_f} \left[ \begin{array}{l} E[\sigma_{L t, d, s, y}^2]_{I SF} \cdot \sum_{j=1}^{N_{L_f}} a_{L_j}^2 \\ + E[\sigma_{L t, d, s, y}]_{I SF}^2 \cdot E[\rho_{L t, d, s, y}]_{I SF} \cdot \left[ \sum_{k=1}^{N_{L_f}} a_{L_k} \right]^2 \\ - E[\sigma_{L t, d, s, y}]_{I SF}^2 \cdot E[\rho_{L t, d, s, y}]_{I SF} \cdot \sum_{j=1}^{N_{L_f}} a_{L_j}^2 \end{array} \right] \quad G.1.3.20$$

$$\text{var of stdev}_{f t, d, s, y} = \frac{\sum_{L=1}^{LG_f} \sum_{i=1}^{N_{L_f}} (V[\sigma_{L t, d, s, y}]_{I SF} \cdot a_{L_i}^4)}{\sum_{L=1}^{LG_f} \sum_{j=1}^{N_{L_f}} a_{L_j}^2} \quad G.1.3.21$$

$$E_{\text{vdstdev}}_{f t, d, s, y} = \sqrt{K_{1f t, d, s, y} - \text{var of stdev}_{f t, d, s, y}} \quad G.1.3.22$$

**Step 5: Expected percentile voltage drop**

$$\mu ns_{f t, d, s, y} = \frac{E_{\text{vdmu}}_{f t, d, s, y} - \text{Channel}_{\min f t, d, s, y}}{\text{Channel}_{\max f t, d, s, y} - \text{Channel}_{\min f t, d, s, y}} \quad G.1.3.23$$

$$\sigma ns_{f t, d, s, y} = \frac{E_{\text{vdstdev}}_{f t, d, s, y}}{\text{Channel}_{\max f t, d, s, y} - \text{Channel}_{\min f t, d, s, y}} \quad G.1.3.24$$

$$Vd_{\alpha f t, d, s, y} = \frac{\mu ns_{f t, d, s, y}^2 - \mu ns_{f t, d, s, y} \cdot (\sigma ns_{f t, d, s, y}^2 + \mu ns_{f t, d, s, y})}{\sigma ns_{f t, d, s, y}^2} \quad G.1.3.25$$

$$Vd_{\beta f t, d, s, y} = \frac{Vd_{\alpha f t, d, s, y} \cdot (1 - \mu ns_{f t, d, s, y})}{\mu ns_{f t, d, s, y}} \quad G.1.3.26$$

$$E[\text{Volt\%tile}]_{f t, d, s, y} = q\beta(p, Vd_{\alpha f t, d, s, y}, Vd_{\beta f t, d, s, y}) \cdot (\text{Channel}_{\max f t, d, s, y} - \text{Channel}_{\min f t, d, s, y}) + \text{Channel}_{\min f t, d, s, y} \quad G.1.3.27$$

**Step 6: Standard deviation set-point for the variance of the percentile voltage drop**

$$Z_{\alpha f t, d, s, y} = \frac{E[\text{Volt\%tile}]_{f t, d, s, y} - E_{v d m u f t, d, s, y}}{E_{v d s t d e v f t, d, s, y}} \quad \text{G.1.3.28}$$

**Step 7: Standard deviation of the expected percentile voltage drop**

$$V_{1 f t, d, s, y} = \sum_{L=1}^{L G_f} V[\mu_{L t, d, s, y}]_{I S F} \cdot \sum_{k=1}^{N_{L f}} a_{L_k}^2 \cdot \left[ \frac{1 + \frac{a_{L_k} \cdot Z_{\alpha f t, d, s, y} \cdot G1_{L t, d, s, y I S F}}{2 \cdot \sqrt{K1_{f t, d, s, y}}} + \frac{Z_{\alpha f t, d, s, y} \cdot G0_{L t, d, s, y I S F} \cdot E[\sigma_{L t, d, s, y}]_{I S F} \cdot E[\rho_{L t, d, s, y}]_{I S F} \cdot \sum a_L}{\sqrt{K1_{f t, d, s, y}}}}{\frac{Z_{\alpha f t, d, s, y} \cdot G0_{L t, d, s, y I S F} \cdot E[\sigma_{L t, d, s, y}]_{I S F} \cdot E[\rho_{L t, d, s, y}]_{I S F} \cdot a_{L_k}}{\sqrt{K1_{f t, d, s, y}}}} \right]^2 \quad \text{G.1.3.29}$$

$$V_{2 f t, d, s, y} = \sum_{L=1}^{L G_f} V e 0_{L t, d, s, y I S F} \cdot \sum_{k=1}^{N_{L f}} a_{L_k}^2 \cdot \left[ \frac{\frac{Z_{\alpha f t, d, s, y} \cdot E[\sigma_{L t, d, s, y}]_{I S F} \cdot E[\rho_{L t, d, s, y}]_{I S F} \cdot \sum a_L}{\sqrt{K1_{f t, d, s, y}}}}{\frac{Z_{\alpha f t, d, s, y} \cdot E[\sigma_{L t, d, s, y}]_{I S F} \cdot E[\rho_{L t, d, s, y}]_{I S F} \cdot a_{L_k}}{\sqrt{K1_{f t, d, s, y}}}} \right]^2 \quad \text{G.1.3.30}$$

$$V_{3 f t, d, s, y} = \sum_{L=1}^{L G_f} V e 1_{L t, d, s, y I S F} \cdot \sum_{k=1}^{N_{L f}} a_{L_k}^2 \cdot \left[ \frac{Z_{\alpha f t, d, s, y} \cdot a_{L_k}}{2 \cdot \sqrt{K1_{f t, d, s, y}}} \right]^2 \quad \text{G.1.3.31}$$

$$V[\text{Volt\%tile}]_{f t, d, s, y} = V_{1 f t, d, s, y} + V_{2 f t, d, s, y} + V_{3 f t, d, s, y} \quad \text{G.1.3.32}$$

$$S[\text{Volt\%tile}]_{f t, d, s, y} = \sqrt{V[\text{Volt\%tile}]_{f t, d, s, y}} \quad \text{G.1.3.33}$$

**Step 8: Total voltage drop**

$$Z_{\alpha p h a r i s k} = \text{norm sin } v(c l) \quad \text{G.1.3.34}$$

$$V_{drop\ f\ t,d,s,y} = E[Volt\%tile]_{f\ t,d,s,y} + Z_{alpharisk} \cdot S[Volt\%tile]_{f\ t,d,s,y} + \sum_{f=1}^{NF_f} FLR_f \cdot FLI_f \quad G.1.3.35$$

$FLR_f = R_{nf} + R_{pf}$  if Fixed Load  $f$  is connected to the phase for which the voltage is being calculated, else if Fixed Load  $f$  is connected to another phase  $FLR_f = -0.5 \cdot R_{nf}$  for star technology and  $FLR_f = -R_{nf}$  for bi-phase technology [ $\Omega$ ]

$$V_{min\ f\ t,d,s,y} = V_{t\ f\ t,d,s,y} - V_{drop\ f\ t,d,s,y} \quad G.1.3.36$$

$V_{min\ f\ t,d,s,y}$  Minimum phase to neutral LV voltage of the calculated phase on feeder  $f$  in time interval  $t$ , day type  $d$ , and season  $s$  in year  $y$  [V]

$V_{t\ f\ t,d,s,y}$  Phase to neutral voltage of the calculated phase at the LV terminals of the MV/LV distribution transformer supplying feeder  $f$  in time interval  $t$ , day type  $d$ , and season  $s$  in year  $y$  [V]

## G.2 QOS VOLTAGE DROP TEST RESULTS IN 1 HOUR INTERVALS

Figure G.2.1: Single node weekday, Saturday and Sunday results ( $p=0.975$ ,  $cl=0.9$ ,  $N=2$ )

Simulated versus calculated voltages: Single node N=2

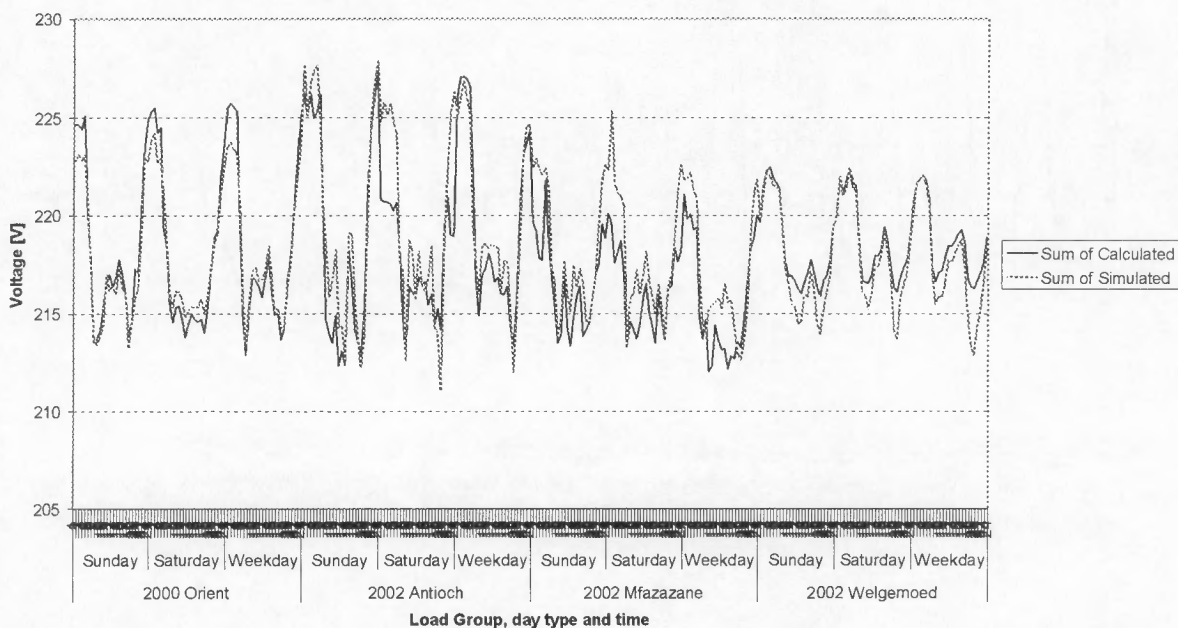


Figure G.2.2: Single node weekday, Saturday and Sunday results ( $p=0.95$ ,  $cl=0.5$ ,  $N=2$ )

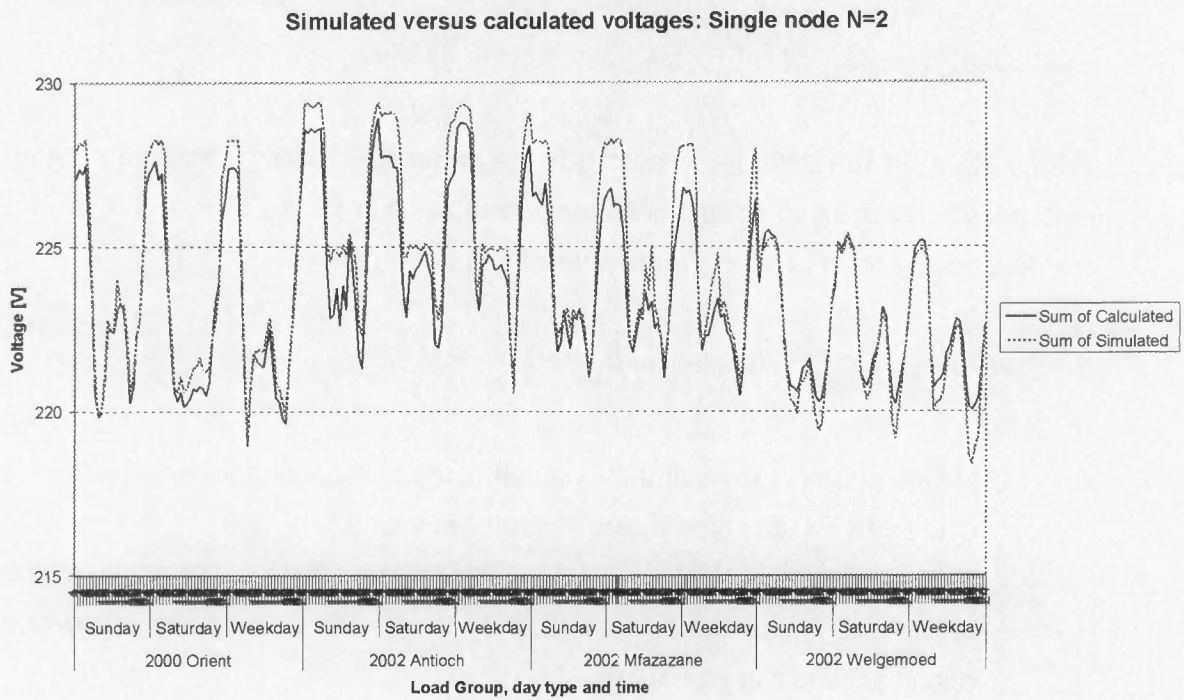


Figure G.2.3: Single node weekday, Saturday and Sunday results ( $p=0.975$ ,  $cl=0.9$ ,  $N=3$ )

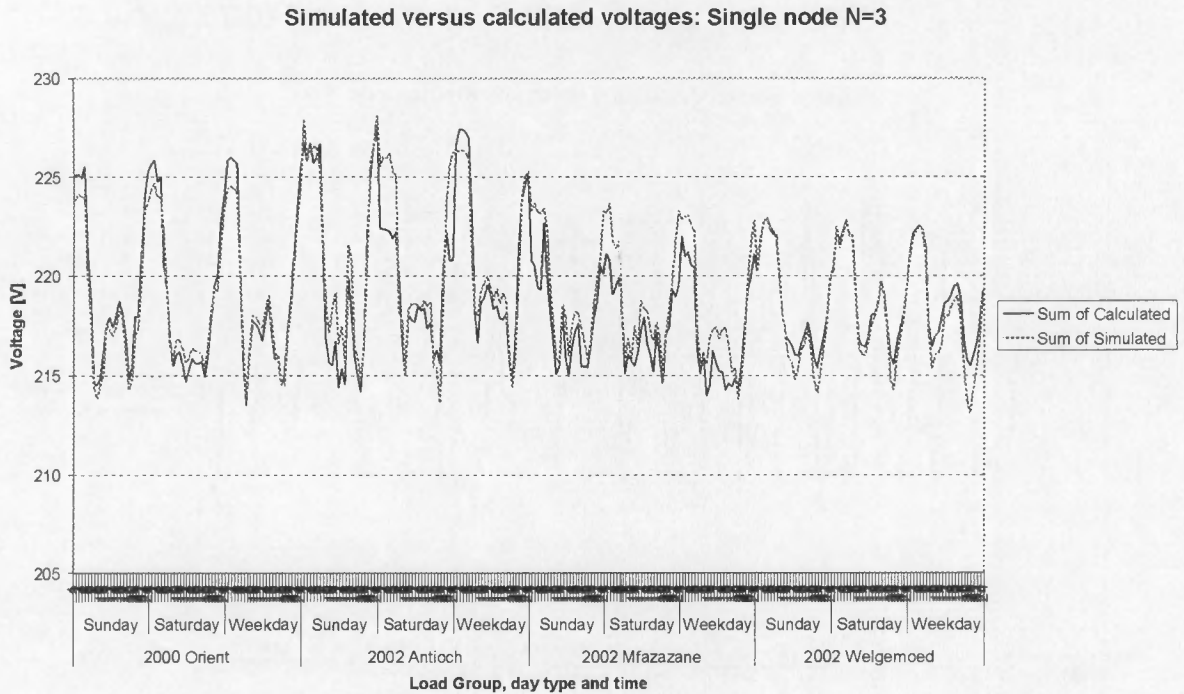


Figure G.2.4: Single node weekday, Saturday and Sunday results ( $p=0.95$ ,  $cl=0.5$ ,  $N=3$ )

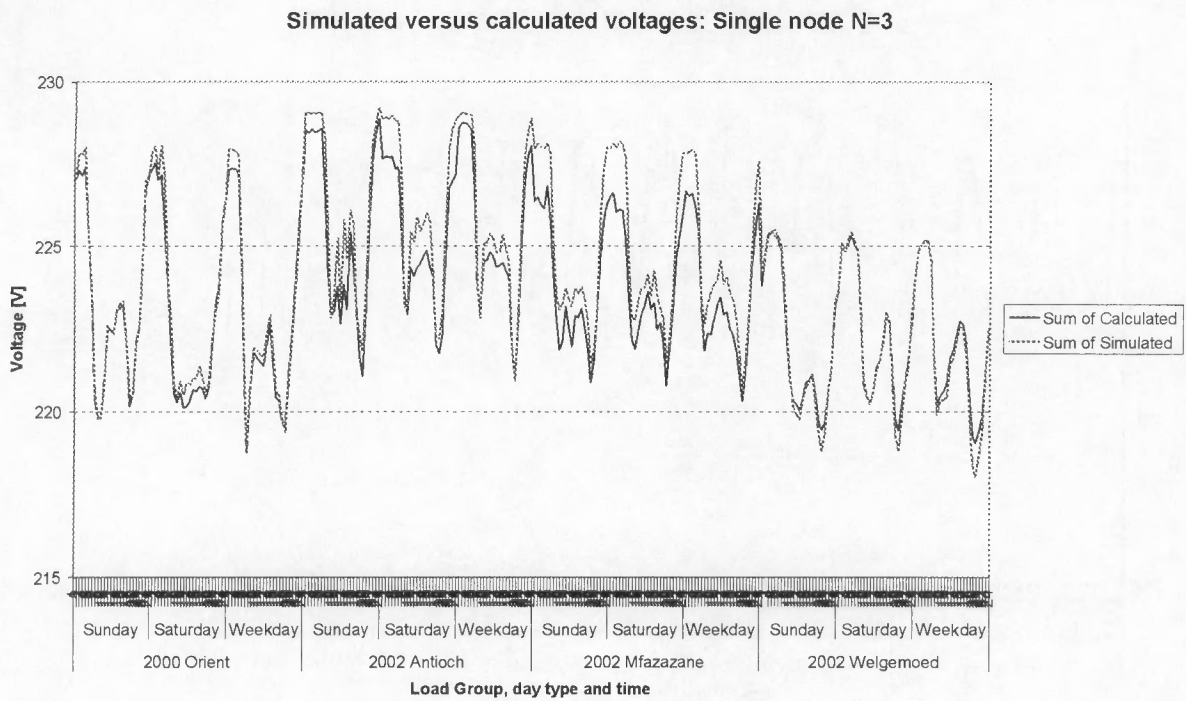


Figure G.2.5: Single node weekday, Saturday and Sunday results ( $p=0.975$ ,  $cl=0.9$ ,  $N=5$ )

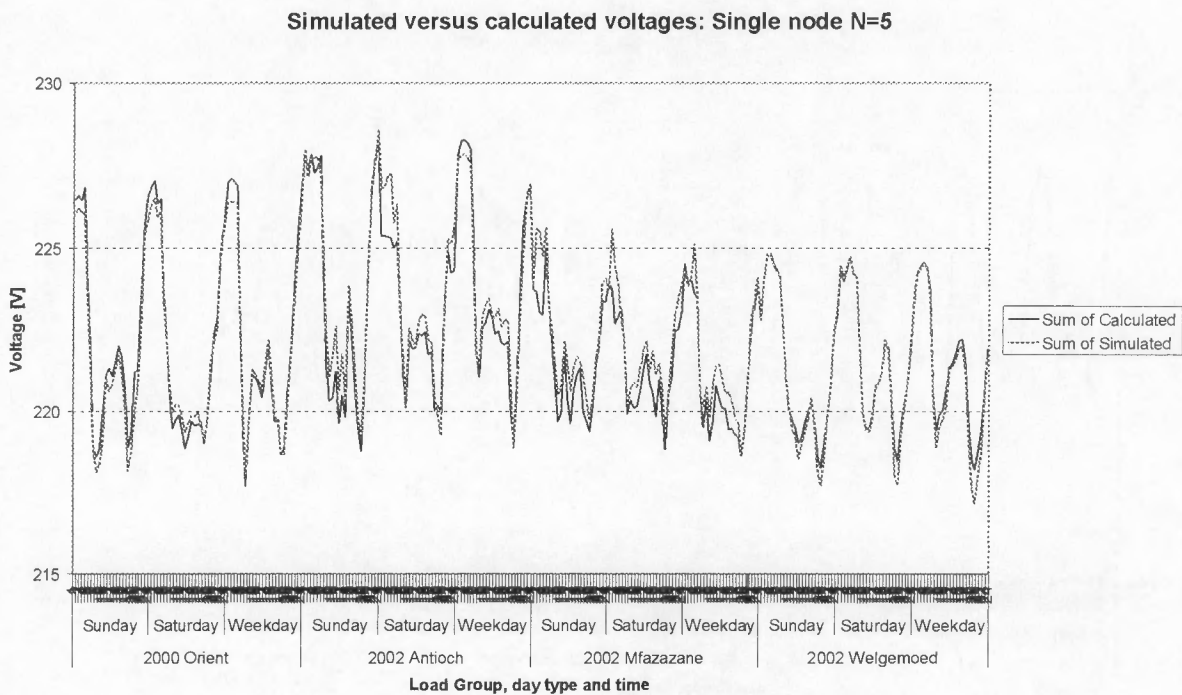


Figure G.2.6: Single node weekday, Saturday and Sunday results ( $p=0.95$ ,  $cl=0.5$ ,  $N=5$ )

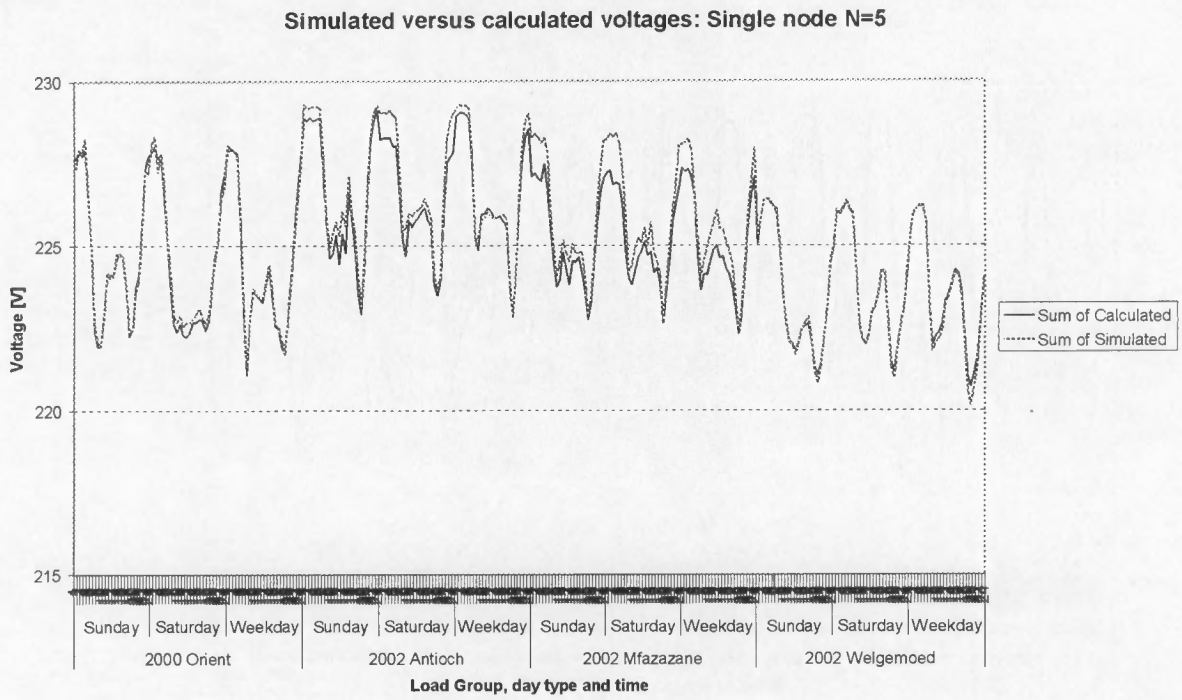


Figure G.2.7: Single node weekday, Saturday and Sunday results ( $p=0.975$ ,  $cl=0.9$ ,  $N=10$ )

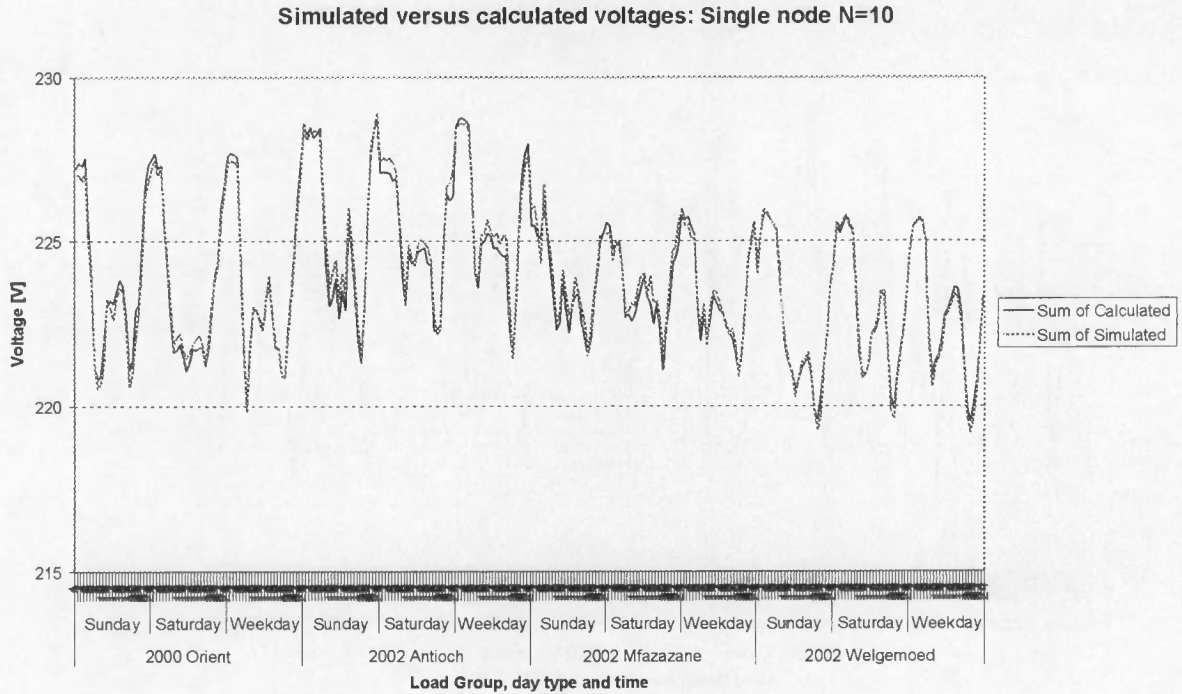


Figure G.2.8: Single node weekday, Saturday and Sunday results ( $p=0.95$ ,  $cl=0.5$ ,  $N=10$ )

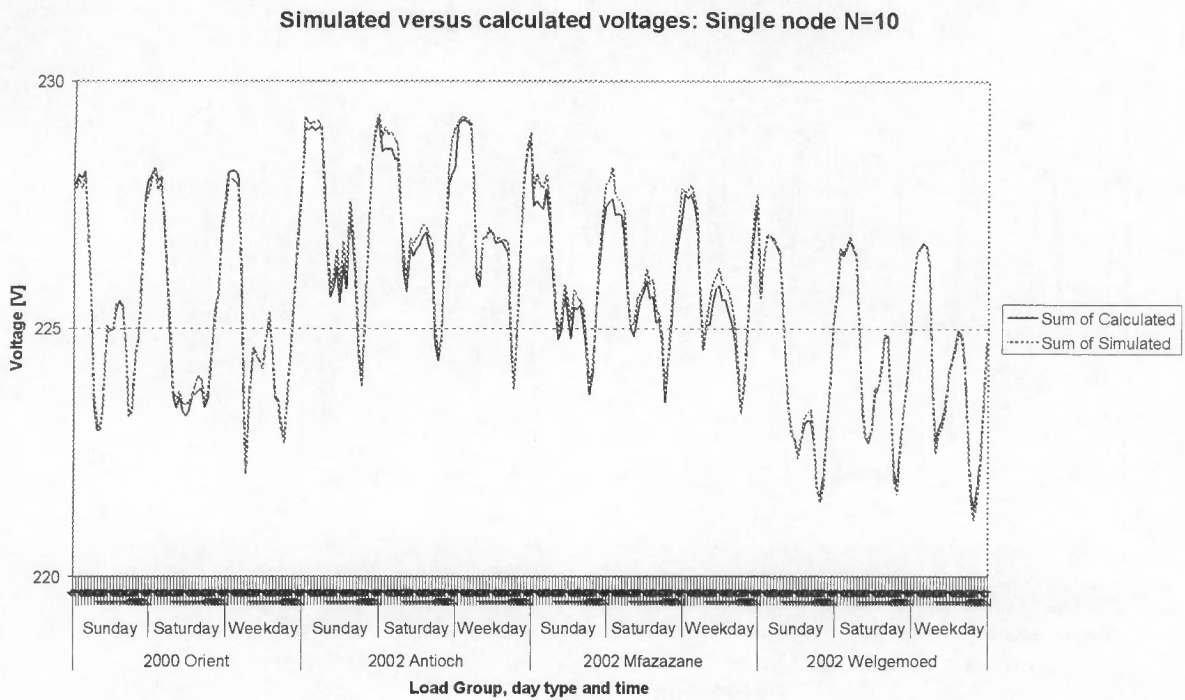


Figure G.2.9: Single node weekday, Saturday and Sunday results ( $p=0.975$ ,  $cl=0.9$ ,  $N=20$ )

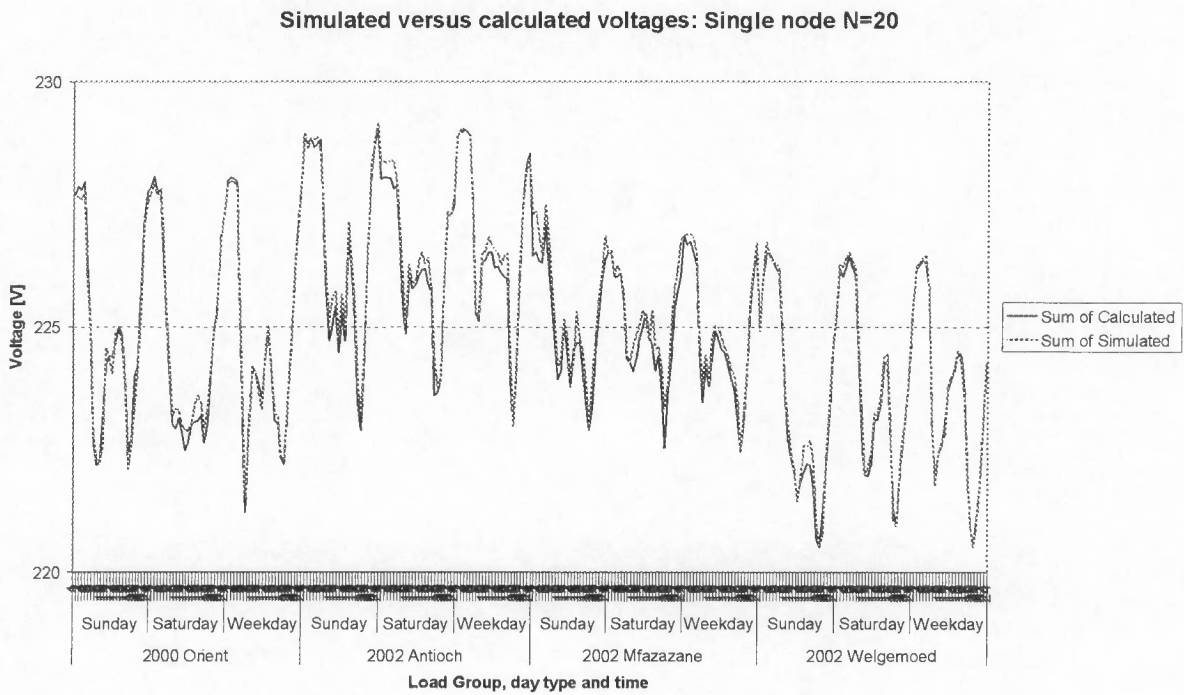
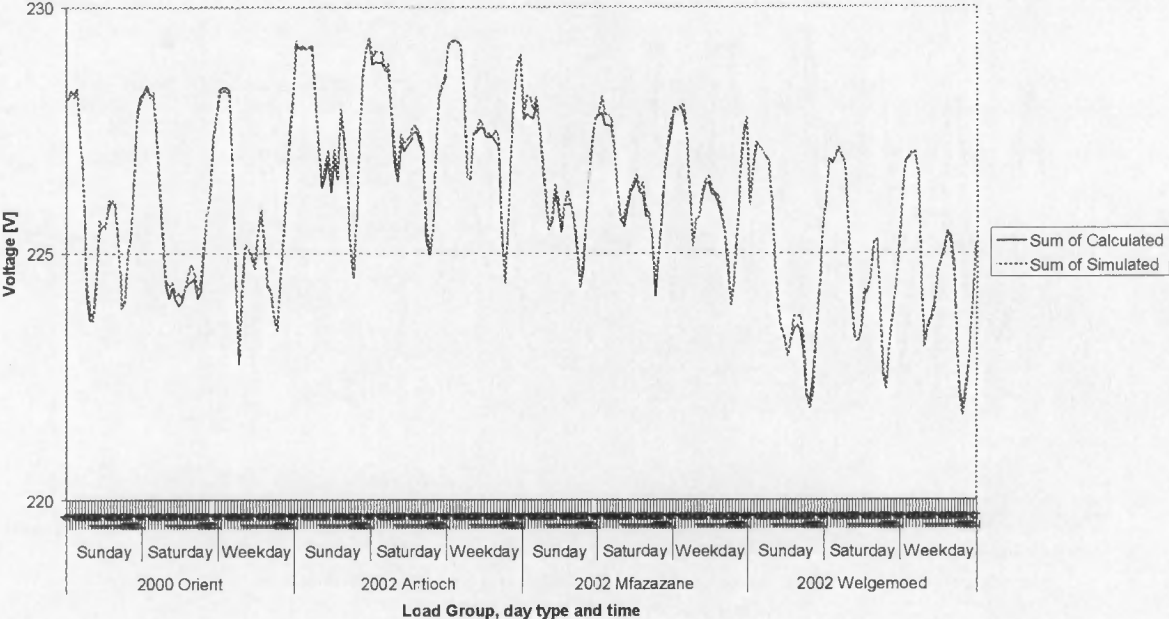


Figure G.2.10: Single node weekday, Saturday and Sunday results (p=0.95, ci=0.5, N=20)

Simulated versus calculated voltages: Single node N=20



# H. APPENDIX H: MV VOLTAGE DROP CALCULATION AND TEST RESULTS

## H.1 METHOD 2: MV/LV TRANSFORMER MV BULK LOAD CALCULATION

### H.1.1 Normalised QOS load

The normalised calculation is performed for a user specified time interval  $t$ , day type  $d$ , season  $s$  and year  $y$ , for each Load Group. The calculations are performed for each MV feeder.

$LG_{mv}$  Number of consumer Load Groups connected to MV feeder  $mv$

$N_{L,mv}$  Number of consumers of Load Group  $L$  connected to MV feeder  $mv$

#### Step 1: Scale load parameters

The time-of-use load parameters are scaled as per step 1 in the LV QOS voltage drop calculation (appendix G.1.3).

#### Step 2: Minimum and maximum current limits for beta current distribution

$$calc_{\min \max Lt,d,s,y} = \frac{C_L \cdot E[\mu_{L,t,d,s,y}]_{I SF} - E[\mu_{L,t,d,s,y}]_{I SF}^2 - E[\sigma_{L,t,d,s,y}]_{I SF}^2}{C_L \cdot E[\sigma_{L,t,d,s,y}]_{I SF}^2} \quad H.1.2.1$$

$$alpha_{\min \max Lt,d,s,y} = E[\mu_{L,t,d,s,y}]_{I SF} \cdot calc_{\min \max Lt,d,s,y} \quad H.1.2.2$$

$$beta_{\min \max Lt,d,s,y} = (C_L - E[\mu_{L,t,d,s,y}]_{I SF}) \cdot calc_{\min \max Lt,d,s,y} \quad H.1.2.3$$

$$Min_{\min \max Lt,d,s,y} = qbeta(0.001, alpha_{\min \max Lt,d,s,y}, beta_{\min \max Lt,d,s,y}) \cdot C_L \quad H.1.2.4$$

$$Max_{\min \max Lt,d,s,y} = qbeta(0.999, alpha_{\min \max Lt,d,s,y}, beta_{\min \max Lt,d,s,y}) \cdot C_L \quad H.1.2.5$$

$$Channel_{\max mv Lt,d,s,y} = N_{L,mv} \cdot Max_{\min \max Lt,d,s,y} \quad H.1.2.6$$

$$Channel_{\min mv L t, d, s, y} = N_{Lmv} \cdot Min_{\min \max L t, d, s, y} \quad H.1.2.7$$

Step 3: Expected value of mean current

$$E_{I_{mu mv L t, d, s, y}} = N_{Lmv} \cdot E[\mu_{L t, d, s, y}]_{I SF} \quad H.1.2.8$$

Step 4: Expected current standard deviation

$$K_{1mv L t, d, s, y} = \left[ E[\sigma^2_{L t, d, s, y}]_{I SF} \cdot N_{Lmv} + E[\sigma_{L t, d, s, y}]_{I SF}^2 \cdot E[\rho_{L t, d, s, y}]_{I SF} \cdot (N_{Lmv}^2 - N_{Lmv}) \right] \quad H.1.2.9$$

$$var\ ofstdev_{mv L t, d, s, y} = V[\sigma_{L t, d, s, y}]_{I SF} \quad H.1.2.10$$

$$E_{Istdev\ mv\ L\ t,\ d,\ s,\ y} = \sqrt{K_{1mv L t, d, s, y} - var\ ofstdev_{mv L t, d, s, y}} \quad H.1.2.11$$

Step 5: Expected percentile current

$$\mu ns_{mv L t, d, s, y} = \frac{E_{I_{mu mv L t, d, s, y}} - Channel_{\min mv L t, d, s, y}}{Channel_{\max mv L t, d, s, y} - Channel_{\min mv L t, d, s, y}} \quad H.1.2.12$$

$$\sigma ns_{mv L t, d, s, y} = \frac{E_{Istdev\ mv\ L\ t,\ d,\ s,\ y}}{Channel_{\max mv L t, d, s, y} - Channel_{\min mv L t, d, s, y}} \quad H.1.2.13$$

$$I_{\alpha mv L t, d, s, y} = \frac{\mu ns_{mv L t, d, s, y}^2 - \mu ns_{mv L t, d, s, y} \cdot (\sigma ns_{mv L t, d, s, y}^2 + \mu ns_{mv L t, d, s, y})}{\sigma ns_{mv L t, d, s, y}^2} \quad H.1.2.14$$

$$I_{\beta mv L t, d, s, y} = \frac{I_{\alpha mv L t, d, s, y} \cdot (1 - \mu ns_{mv L t, d, s, y})}{\mu ns_{mv L t, d, s, y}} \quad H.1.2.15$$

$$E[I\%tile]_{mv L t, d, s, y} = qbeta(p, I_{\alpha mv L t, d, s, y}, I_{\beta mv L t, d, s, y}) \cdot (Channel_{\max mv L t, d, s, y} - Channel_{\min mv L t, d, s, y}) + Channel_{\min mv L t, d, s, y} \quad H.1.2.16$$

Step 6: Standard deviation set-point for the variance of the percentile current

$$Z_{\alpha mvL t, d, s, y} = \frac{E[I^{\%tile}]_{mvL t, d, s, y} - E_{Imu mvL t, d, s, y}}{E_{Istd ev mvL t, d, s, y}} \quad H.1.2.17$$

Step 7: Standard deviation of the expected percentile current

$$V_{1 mvL t, d, s, y} = V[\mu_{L t, d, s, y}]_{I SF} \cdot N_{Lmv} \cdot \left[ 1 + \frac{Z_{\alpha mvL t, d, s, y} \cdot G1_{L t, d, s, y I SF}}{2 \cdot \sqrt{K_{1 mvL t, d, s, y}}} + \frac{Z_{\alpha fL t, d, s, y} \cdot G0_{L t, d, s, y I SF} \cdot E[\sigma_{L t, d, s, y}]_{I SF} \cdot E[\rho_{L t, d, s, y}]_{I SF}}{\sqrt{K_{1 mvL t, d, s, y}}} \cdot (N_{Lmv} - 1) \right]^2 \quad H.1.2.18$$

$$V_{2 mvL t, d, s, y} = Ve0_{L t, d, s, y I SF} \cdot N_{Lmv} \cdot \left[ \frac{Z_{\alpha mvL t, d, s, y} \cdot E[\sigma_{L t, d, s, y}]_{I SF} \cdot E[\rho_{L t, d, s, y}]_{I SF}}{\sqrt{K_{1 mvL t, d, s, y}}} \cdot (N_{Lmv} - 1) \right]^2 \quad H.1.2.19$$

$$V_{3 mvL t, d, s, y} = Ve1_{L t, d, s, y I SF} \cdot N_{Lmv} \cdot \left[ \frac{Z_{\alpha mvL t, d, s, y}}{2 \cdot \sqrt{K_{1 mvL t, d, s, y}}} \right]^2 \quad H.1.2.20$$

$$V[I^{\%tile}]_{mvL t, d, s, y} = V_{1 mvL t, d, s, y} + V_{2 mvL t, d, s, y} + V_{3 mvL t, d, s, y} \quad H.1.2.21$$

$$S[I^{\%tile}]_{mvL t, d, s, y} = \sqrt{V[I^{\%tile}]_{mvL t, d, s, y}} \quad H.1.2.22$$

Step 8: Total current

$$Z_{\alpha pharisk} = norm \sin v(cl) \quad H.1.2.23$$

$$I_{mvL t, d, s, y} = E[I^{\%tile}]_{mvL t, d, s, y} + Z_{\alpha pharisk} \cdot S[I^{\%tile}]_{mvL t, d, s, y} \quad H.1.2.24$$

Step 9: Diversified apparent power per consumer

$$DIVP_{mv\ L\ t,d,s,y} = \frac{I_{mv\ L\ t,d,s,y} \cdot V_{LV}}{N_{Lmv} \cdot 1000} \quad \text{H.1.2.25}$$

H.1.2 MV/LV transformer MV bulk loads

The magnitude of the active power [kW] of the MV bulk load connected to transformer T on MV feeder mv in time interval t, day type d, season s and year y is given by:

$$BLAP_{mvT\ t,d,s,y} = \sum_{L=1}^{LG_T} N_{TL} \cdot DIVP_{mv\ L\ t,d,s,y} \cdot PF_{L\ t,d,s} + \sum_{f=1}^{NF_T} F_{Tf} \cdot FS_{Tf} \cdot FPF_{Tf} \quad \text{H.1.2.26}$$

$BLAP_{mvT\ t,d,s,y}$  MV bulk load active power in time interval t, day type d, season s and year y for transformer T on MV feeder mv [kW]

$LG_T$  Number of Load Groups connected to transformer T

$N_{TL}$  Number of consumers in Load Group L connected to transformer T

$NF_T$  Number of Fixed Loads connected to transformer T

$F_{Tf}$  Magnitude of Fixed Load f connected to transformer T [kVA]

$FS_{Tf}$  Scaling factor of Fixed Load f connected to transformer T [per-unit]

$FPF_{Tf}$  Power factor of Fixed Load f connected to transformer T [ratio]

The magnitude of the reactive power [kVAR] of the MV bulk load connected to transformer T on MV feeder mv in time interval t, day type d, season s and year y is given by:

$$BLRP_{mvT\ t,d,s,y} = \sum_{L=1}^{LG_T} N_{TL} \cdot DIVP_{mv\ L\ t,d,s,y} \cdot \sin(\arccos(PF_{L\ t,d,s})) + \sum_{f=1}^{NF_T} F_{Tf} \cdot FS_{Tf} \cdot \sin(\arccos(FPF_{Tf})) \quad \text{H.1.2.27}$$

$BLRP_{mvT\ t,d,s,y}$  MV bulk load reactive power in time interval t, day type d, season s and year y for transformer T on MV feeder mv [kVAR]

## H.2 GENERIC MV NETWORK TEST RESULTS

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<u>Nv=20, NMV=300</u>					
Method 1: Undiversified MV loads	53.99%	30.89%	16.54%	N/A	N/A
Method 2: Diversified MV loads	-2.82%	-2.82%	-2.82%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	13.43%	13.43%	13.43%	N/A	N/A
<u>Nv=40, NMV=600</u>					
Method 1: Undiversified MV loads	57.78%	34.12%	19.41%	10.37%	N/A
Method 2: Diversified MV loads	-1.78%	-1.78%	-1.78%	-1.78%	N/A
Method 3: Undiversified loads lumped onto MV laterals	8.49%	8.49%	8.49%	8.49%	N/A
<u>Nv=100, NMV=1500</u>					
Method 1: Undiversified MV loads	60.84%	36.72%	21.73%	12.51%	5.60%
Method 2: Diversified MV loads	-0.98%	-0.98%	-0.98%	-0.98%	-0.98%
Method 3: Undiversified loads lumped onto MV laterals	4.60%	4.60%	4.60%	4.60%	4.60%
<u>Nv=200, NMV=3000</u>					
Method 1: Undiversified MV loads	62.24%	37.91%	22.79%	13.49%	6.52%
Method 2: Diversified MV loads	-0.64%	-0.64%	-0.64%	-0.64%	-0.64%
Method 3: Undiversified loads lumped onto MV laterals	2.91%	2.91%	2.91%	2.91%	2.91%
<u>Nv=300, NMV=4500</u>					
Method 1: Undiversified MV loads	62.83%	38.41%	23.23%	13.90%	6.90%
Method 2: Diversified MV loads	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
Method 3: Undiversified loads lumped onto MV laterals	2.24%	2.24%	2.24%	2.24%	2.24%

Table H.1: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Welgemoed, weekday, 18:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<u>Nv=20, NMV=300</u>					
Method 1: Undiversified MV loads	68.31%	40.09%	22.05%	N/A	N/A
Method 2: Diversified MV loads	-3.76%	-3.76%	-3.76%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	17.45%	17.45%	17.45%	N/A	N/A
<u>Nv=40, NMV=600</u>					
Method 1: Undiversified MV loads	73.84%	44.69%	26.06%	14.16%	N/A
Method 2: Diversified MV loads	-2.40%	-2.40%	-2.40%	-2.40%	N/A
Method 3: Undiversified loads lumped onto MV laterals	11.26%	11.26%	11.26%	11.26%	N/A
<u>Nv=100, NMV=1500</u>					
Method 1: Undiversified MV loads	78.29%	48.40%	29.29%	17.09%	7.61%
Method 2: Diversified MV loads	-1.29%	-1.29%	-1.29%	-1.29%	-1.29%
Method 3: Undiversified loads lumped onto MV laterals	6.15%	6.15%	6.15%	6.15%	6.15%
<u>Nv=200, NMV=3000</u>					
Method 1: Undiversified MV loads	80.29%	50.06%	30.74%	18.40%	8.81%
Method 2: Diversified MV loads	-0.81%	-0.81%	-0.81%	-0.81%	-0.81%
Method 3: Undiversified loads lumped onto MV laterals	3.85%	3.85%	3.85%	3.85%	3.85%
<u>Nv=300, NMV=4500</u>					
Method 1: Undiversified MV loads	81.10%	50.74%	31.33%	18.93%	9.30%
Method 2: Diversified MV loads	-0.62%	-0.62%	-0.62%	-0.62%	-0.62%
Method 3: Undiversified loads lumped onto MV laterals	2.93%	2.93%	2.93%	2.93%	2.93%

Table H.2: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Welgemoed, weekday, 11:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	81.72%	47.06%	25.46%	N/A	N/A
Method 2: Diversified MV loads	-4.31%	-4.31%	-4.31%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	20.52%	20.52%	20.52%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	88.57%	52.61%	30.19%	16.19%	N/A
Method 2: Diversified MV loads	-2.73%	-2.73%	-2.73%	-2.73%	N/A
Method 3: Undiversified loads lumped onto MV laterals	13.08%	13.08%	13.08%	13.08%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	94.09%	57.07%	34.00%	19.59%	8.62%
Method 2: Diversified MV loads	-1.47%	-1.47%	-1.47%	-1.47%	-1.47%
Method 3: Undiversified loads lumped onto MV laterals	7.06%	7.06%	7.06%	7.06%	7.06%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	96.55%	59.06%	35.70%	21.11%	10.00%
Method 2: Diversified MV loads	-0.92%	-0.92%	-0.92%	-0.92%	-0.92%
Method 3: Undiversified loads lumped onto MV laterals	4.39%	4.39%	4.39%	4.39%	4.39%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	97.56%	59.88%	36.40%	21.73%	10.56%
Method 2: Diversified MV loads	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%
Method 3: Undiversified loads lumped onto MV laterals	3.33%	3.33%	3.33%	3.33%	3.33%

Table H.3: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Welgemoed, weekday, 1:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	90.89%	53.95%	30.27%	N/A	N/A
Method 2: Diversified MV loads	-5.32%	-5.32%	-5.32%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	23.88%	23.88%	23.88%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	100.11%	61.38%	36.56%	20.47%	N/A
Method 2: Diversified MV loads	-3.55%	-3.55%	-3.55%	-3.55%	N/A
Method 3: Undiversified loads lumped onto MV laterals	16.03%	16.03%	16.03%	16.03%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	107.92%	67.67%	41.89%	25.17%	11.68%
Method 2: Diversified MV loads	-1.99%	-1.99%	-1.99%	-1.99%	-1.99%
Method 3: Undiversified loads lumped onto MV laterals	9.16%	9.16%	9.16%	9.16%	9.16%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	111.51%	70.57%	44.34%	27.34%	13.61%
Method 2: Diversified MV loads	-1.26%	-1.26%	-1.26%	-1.26%	-1.26%
Method 3: Undiversified loads lumped onto MV laterals	5.88%	5.88%	5.88%	5.88%	5.88%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	112.98%	71.76%	45.35%	28.22%	14.40%
Method 2: Diversified MV loads	-0.96%	-0.96%	-0.96%	-0.96%	-0.96%
Method 3: Undiversified loads lumped onto MV laterals	4.51%	4.51%	4.51%	4.51%	4.51%

Table H.4: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Mfazazane, weekday, 19:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<u>Nv=20, NMV=300</u>					
Method 1: Undiversified MV loads	203.48%	114.47%	61.50%	N/A	N/A
Method 2: Diversified MV loads	-10.70%	-10.70%	-10.70%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	51.10%	51.10%	51.10%	N/A	N/A
<u>Nv=40, NMV=600</u>					
Method 1: Undiversified MV loads	234.06%	136.08%	77.77%	42.24%	N/A
Method 2: Diversified MV loads	-7.30%	-7.30%	-7.30%	-7.30%	N/A
Method 3: Undiversified loads lumped onto MV laterals	34.48%	34.48%	34.48%	34.48%	N/A
<u>Nv=100, NMV=1500</u>					
Method 1: Undiversified MV loads	261.76%	155.66%	92.51%	54.03%	24.51%
Method 2: Diversified MV loads	-4.18%	-4.18%	-4.18%	-4.18%	-4.18%
Method 3: Undiversified loads lumped onto MV laterals	19.73%	19.73%	19.73%	19.73%	19.73%
<u>Nv=200, NMV=3000</u>					
Method 1: Undiversified MV loads	275.08%	165.07%	99.60%	59.70%	29.10%
Method 2: Diversified MV loads	-2.68%	-2.68%	-2.68%	-2.68%	-2.68%
Method 3: Undiversified loads lumped onto MV laterals	12.66%	12.66%	12.66%	12.66%	12.66%
<u>Nv=300, NMV=4500</u>					
Method 1: Undiversified MV loads	280.65%	169.01%	102.56%	62.07%	31.01%
Method 2: Diversified MV loads	-2.05%	-2.05%	-2.05%	-2.05%	-2.05%
Method 3: Undiversified loads lumped onto MV laterals	9.70%	9.70%	9.70%	9.70%	9.70%

Table H.5: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Mfazazane, weekday, 11:00, July 2002, p=0.975, cl=0.9, R<sub>ratio</sub>=2.5)

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<u>Nv=20, NMV=300</u>					
Method 1: Undiversified MV loads	158.47%	90.91%	50.17%	N/A	N/A
Method 2: Diversified MV loads	-9.18%	-9.18%	-9.18%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	41.25%	41.25%	41.25%	N/A	N/A
<u>Nv=40, NMV=600</u>					
Method 1: Undiversified MV loads	182.40%	108.58%	64.07%	36.37%	N/A
Method 2: Diversified MV loads	-6.88%	-6.88%	-6.88%	-6.88%	N/A
Method 3: Undiversified loads lumped onto MV laterals	29.29%	29.29%	29.29%	29.29%	N/A
<u>Nv=100, NMV=1500</u>					
Method 1: Undiversified MV loads	208.51%	127.86%	79.24%	48.98%	24.80%
Method 2: Diversified MV loads	-4.62%	-4.62%	-4.62%	-4.62%	-4.62%
Method 3: Undiversified loads lumped onto MV laterals	19.56%	19.56%	19.56%	19.56%	19.56%
<u>Nv=200, NMV=3000</u>					
Method 1: Undiversified MV loads	215.03%	132.68%	83.03%	52.13%	27.44%
Method 2: Diversified MV loads	-1.53%	-1.53%	-1.53%	-1.53%	-1.53%
Method 3: Undiversified loads lumped onto MV laterals	11.60%	11.60%	11.60%	11.60%	11.60%
<u>Nv=300, NMV=4500</u>					
Method 1: Undiversified MV loads	216.46%	133.74%	83.86%	52.83%	28.02%
Method 2: Diversified MV loads	-1.03%	-1.03%	-1.03%	-1.03%	-1.03%
Method 3: Undiversified loads lumped onto MV laterals	7.34%	7.34%	7.34%	7.34%	7.34%

Table H.6: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Mfazazane, weekday, 1:00, July 2002, p=0.975, cl=0.9, R<sub>ratio</sub>=2.5)

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	203.48%	114.47%	61.50%	N/A	N/A
Method 2: Diversified MV loads	-10.70%	-10.70%	-10.70%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	51.10%	51.10%	51.10%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	234.06%	136.08%	77.77%	42.24%	N/A
Method 2: Diversified MV loads	-7.30%	-7.30%	-7.30%	-7.30%	N/A
Method 3: Undiversified loads lumped onto MV laterals	34.48%	34.48%	34.48%	34.48%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	261.76%	155.66%	92.51%	54.03%	24.51%
Method 2: Diversified MV loads	-4.18%	-4.18%	-4.18%	-4.18%	-4.18%
Method 3: Undiversified loads lumped onto MV laterals	19.73%	19.73%	19.73%	19.73%	19.73%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	275.08%	165.07%	99.60%	59.70%	29.10%
Method 2: Diversified MV loads	-2.68%	-2.68%	-2.68%	-2.68%	-2.68%
Method 3: Undiversified loads lumped onto MV laterals	12.66%	12.66%	12.66%	12.66%	12.66%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	280.65%	169.01%	102.56%	62.07%	31.01%
Method 2: Diversified MV loads	-2.05%	-2.05%	-2.05%	-2.05%	-2.05%
Method 3: Undiversified loads lumped onto MV laterals	9.70%	9.70%	9.70%	9.70%	9.70%

Table H.5: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Mfazazane, weekday, 11:00, July 2002, p=0.975, cl=0.9, R<sub>ratio</sub>=2.5)

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	158.47%	90.91%	50.17%	N/A	N/A
Method 2: Diversified MV loads	-9.18%	-9.18%	-9.18%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	41.25%	41.25%	41.25%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	182.40%	108.58%	64.07%	36.37%	N/A
Method 2: Diversified MV loads	-6.88%	-6.88%	-6.88%	-6.88%	N/A
Method 3: Undiversified loads lumped onto MV laterals	29.29%	29.29%	29.29%	29.29%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	208.51%	127.86%	79.24%	48.98%	24.80%
Method 2: Diversified MV loads	-4.62%	-4.62%	-4.62%	-4.62%	-4.62%
Method 3: Undiversified loads lumped onto MV laterals	19.56%	19.56%	19.56%	19.56%	19.56%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	215.03%	132.68%	83.03%	52.13%	27.44%
Method 2: Diversified MV loads	-1.53%	-1.53%	-1.53%	-1.53%	-1.53%
Method 3: Undiversified loads lumped onto MV laterals	11.60%	11.60%	11.60%	11.60%	11.60%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	216.46%	133.74%	83.86%	52.83%	28.02%
Method 2: Diversified MV loads	-1.03%	-1.03%	-1.03%	-1.03%	-1.03%
Method 3: Undiversified loads lumped onto MV laterals	7.34%	7.34%	7.34%	7.34%	7.34%

Table H.6: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Mfazazane, weekday, 1:00, July 2002, p=0.975, cl=0.9, R<sub>ratio</sub>=2.5)

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	112.29%	65.14%	35.86%	N/A	N/A
Method 2: Diversified MV loads	-6.25%	-6.25%	-6.25%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	28.87%	28.87%	28.87%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	124.33%	74.52%	43.57%	24.04%	N/A
Method 2: Diversified MV loads	-4.14%	-4.14%	-4.14%	-4.14%	N/A
Method 3: Undiversified loads lumped onto MV laterals	19.15%	19.15%	19.15%	19.15%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	134.55%	82.46%	50.11%	29.68%	13.58%
Method 2: Diversified MV loads	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%
Method 3: Undiversified loads lumped onto MV laterals	10.79%	10.79%	10.79%	10.79%	10.79%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	139.24%	86.11%	53.11%	32.28%	15.85%
Method 2: Diversified MV loads	-1.46%	-1.46%	-1.46%	-1.46%	-1.46%
Method 3: Undiversified loads lumped onto MV laterals	6.86%	6.86%	6.86%	6.86%	6.86%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	141.17%	87.61%	54.35%	33.34%	16.78%
Method 2: Diversified MV loads	-1.11%	-1.11%	-1.11%	-1.11%	-1.11%
Method 3: Undiversified loads lumped onto MV laterals	5.25%	5.25%	5.25%	5.25%	5.25%

Table H.7: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Antioch, weekday, 19:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	332.02%	193.00%	107.68%	N/A	N/A
Method 2: Diversified MV loads	-12.72%	-12.72%	-12.72%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	87.35%	87.35%	87.35%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	345.83%	202.37%	114.31%	58.86%	N/A
Method 2: Diversified MV loads	-3.18%	-3.18%	-3.18%	-3.18%	N/A
Method 3: Undiversified loads lumped onto MV laterals	42.07%	42.07%	42.07%	42.07%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	346.12%	202.56%	114.45%	58.96%	12.38%
Method 2: Diversified MV loads	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%
Method 3: Undiversified loads lumped onto MV laterals	6.27%	6.27%	6.27%	6.27%	6.27%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	348.80%	204.38%	115.74%	59.91%	13.05%
Method 2: Diversified MV loads	1.14%	1.14%	1.14%	1.14%	1.14%
Method 3: Undiversified loads lumped onto MV laterals	5.08%	5.08%	5.08%	5.08%	5.08%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	346.63%	202.91%	114.70%	59.14%	12.50%
Method 2: Diversified MV loads	0.84%	0.84%	0.84%	0.84%	0.84%
Method 3: Undiversified loads lumped onto MV laterals	2.71%	2.71%	2.71%	2.71%	2.71%

Table H.8: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Antioch, weekday, 11:00, July 2002,  $p=0.975$ ,  $cl=0.9$ ,  $R_{ratio}=2.5$ )

Errors in MV voltage drop assessment	Customers per MV/LV transformer (T)				
	5	10	20	40	100
<b>Nv=20, NMV=300</b>					
Method 1: Undiversified MV loads	231.63%	128.08%	68.40%	N/A	N/A
Method 2: Diversified MV loads	-12.31%	-12.31%	-12.31%	N/A	N/A
Method 3: Undiversified loads lumped onto MV laterals	58.21%	58.21%	58.21%	N/A	N/A
<b>Nv=40, NMV=600</b>					
Method 1: Undiversified MV loads	272.80%	156.39%	89.30%	49.30%	N/A
Method 2: Diversified MV loads	-9.07%	-9.07%	-9.07%	-9.07%	N/A
Method 3: Undiversified loads lumped onto MV laterals	40.81%	40.81%	40.81%	40.81%	N/A
<b>Nv=100, NMV=1500</b>					
Method 1: Undiversified MV loads	316.52%	186.46%	111.51%	66.82%	32.47%
Method 2: Diversified MV loads	-6.21%	-6.21%	-6.21%	-6.21%	-6.21%
Method 3: Undiversified loads lumped onto MV laterals	25.95%	25.95%	25.95%	25.95%	25.95%
<b>Nv=200, NMV=3000</b>					
Method 1: Undiversified MV loads	344.38%	205.62%	125.65%	77.97%	41.33%
Method 2: Diversified MV loads	-5.22%	-5.22%	-5.22%	-5.22%	-5.22%
Method 3: Undiversified loads lumped onto MV laterals	19.37%	19.37%	19.37%	19.37%	19.37%
<b>Nv=300, NMV=4500</b>					
Method 1: Undiversified MV loads	356.36%	213.86%	131.74%	82.77%	45.14%
Method 2: Diversified MV loads	-2.90%	-2.90%	-2.90%	-2.90%	-2.90%
Method 3: Undiversified loads lumped onto MV laterals	16.07%	16.07%	16.07%	16.07%	16.07%

Table H.9: Errors in deterministic MV voltage drop assessment as compared to QOS load model (2002 Antioch, weekday, 1:00, July 2002, p=0.975, cl=0.9, R<sub>ratio</sub>=2.5)

# I. APPENDIX I: ESKOM 2005 WEPS CHARGES

Energy charge period	Weekday	Saturday	Sunday
Peak	07:00-10:00 & 18:00-20:00	N/A	N/A
Standard	06:00-07:00, 10:00- 18:00 & 20:00-22:00	07:00-12:00 & 18:00-20:00	N/A
Off-peak	22:00-06:00	20:00-07:00 & 12:00-18:00	0:00-24:00

Table I.1: 2005 WEPS time periods [Eskom, 2005a]

Energy charge period	Low Season [c/kWh] (Sept to May)	High Season [c/kWh] (June, July and Aug)
Peak	14.58	54.00
Standard	8.67	13.53
Off-peak	5.86	6.91

Table I.2: 2005 WEPS energy charges [Eskom, 2005a] (R6≈1US\$)

Distance from Johannesburg	Zone	Transmission network charge [Rand/kVA/month]	Transmission loss factor	Reliability charge [c/kWh]
0 to 300 km	1	R 2.5490	1.0128	0.1506
301 to 600 km	2	R 2.5745	1.0228	
601 to 900 km	3	R 2.6000	1.0328	
> 900 km	4	R 2.6255	1.0428	

Table I.3: 2005 WEPS Transmission network charges, reliability services charges and loss factors [Eskom, 2005a]

Zone 3 charges have been utilised in this research. All charges exclude VAT.

## J. APPENDIX J: CONDUCTOR PARAMETERS

Name	Tech	Ap [mm <sup>2</sup> ]	An [mm <sup>2</sup> ]	Rp+ve [Ω/km]	Xp+ve [Ω/km]	Bp+ve [uS/km]	Rn [Ω/km]	Xn [Ω/km]	Bn [uS/km]	Rating [amps]	Capital Cost [Rand/km]
22kV Phase-to-phase Squirrel	2P2W	24.48	N/A	1.505	0.378	3.038	N/A	N/A	N/A	105	R 37,972
22kV Phase-to-phase Fox	2P2W	42.80	N/A	0.845	0.361	3.193	N/A	N/A	N/A	148	R 44,284
22kV Phase-to-phase Mink	2P2W	73.65	N/A	0.500	0.344	3.359	N/A	N/A	N/A	209	R 57,567
22kV Phase-to-phase Hare	2P2W	122.48	N/A	0.296	0.328	3.532	N/A	N/A	N/A	292	R 71,842
22kV Three phase Squirrel	3P3W	24.48	N/A	1.505	0.360	3.201	N/A	N/A	N/A	105	R 52,190
22kV Three phase Fox	3P3W	42.80	N/A	0.845	0.343	3.370	N/A	N/A	N/A	148	R 61,117
22kV Three phase Mink	3P3W	73.65	N/A	0.500	0.325	3.557	N/A	N/A	N/A	209	R 79,850
22kV Three phase Hare	3P3W	122.48	N/A	0.296	0.309	3.751	N/A	N/A	N/A	292	R 100,115
19kV SWER Squirrel	1P1W	24.48	N/A	1.553	0.809	2.022	N/A	N/A	N/A	105	R 34,640
19kV SWER Fox	1P1W	42.80	N/A	0.894	0.791	2.089	N/A	N/A	N/A	148	R 39,529
19kV SWER Mink	1P1W	73.65	N/A	0.549	0.774	2.159	N/A	N/A	N/A	209	R 50,124
19kV SWER Hare	1P1W	122.48	N/A	0.344	0.759	2.229	N/A	N/A	N/A	292	R 61,027

Table J.1: MV conductor parameters. Ap and An are the phase and neutral conductor areas respectively. The capital cost includes materials, labour and typical engineering and design fees

Name	Tech	Ap [mm <sup>2</sup> ]	An [mm <sup>2</sup> ]	Rp+ve [Ω/km]	Xp+ve [Ω/km]	Bp+ve [uS/km]	Rn [Ω/km]	Xn [Ω/km]	Bn [uS/km]	Rating [amps]	Capital Cost [Rand/km]
230V Single phase Airdac 4mm <sup>2</sup> Cu	1P2W	4	4	4.990	0	0	4.990	0	0	37	R 35,978
230V Single phase Airdac 10mm <sup>2</sup> Cu	1P2W	10	10	2.000	0	0	2.000	0	0	65	R 44,136
230V Single phase ABC 25mm <sup>2</sup> Al	1P2W	25	35	1.297	0.096	0	1.065	0.096	0	105	R 44,042
230V Single phase ABC 35mm <sup>2</sup> Al	1P2W	35	35	0.938	0.096	0	1.065	0.096	0	144	R 47,746
230V Single phase ABC 50mm <sup>2</sup> Al	1P2W	50	35	0.693	0.090	0	0.778	0.090	0	183	R 53,133
230V Single phase ABC 70mm <sup>2</sup> Al	1P2W	70	50	0.479	0.089	0	0.778	0.090	0	228	R 62,904
230V Single phase ABC 95mm <sup>2</sup> Al	1P2W	95	50	0.346	0.086	0	0.778	0.090	0	277	R 69,645
460V Bi-phase ABC 25mm <sup>2</sup> Al	2P3W	25	35	1.297	0.096	0	1.065	0.096	0	105	R 51,255
460V Bi-phase ABC 35mm <sup>2</sup> Al	2P3W	35	35	0.938	0.096	0	1.065	0.096	0	144	R 55,638
460V Bi-phase ABC 50mm <sup>2</sup> Al	2P3W	50	35	0.693	0.090	0	0.778	0.090	0	183	R 61,689
460V Bi-phase ABC 70mm <sup>2</sup> Al	2P3W	70	50	0.479	0.089	0	0.778	0.090	0	228	R 69,850
460V Bi-phase ABC 95mm <sup>2</sup> Al	2P3W	95	50	0.346	0.086	0	0.778	0.090	0	277	R 78,573

Table J.2: LV conductor parameters

(Reactance in service cables and charging capacitance of LV networks has been ignored)